Janet L. Fraser  
Director, Regulatory Affairs  
Phone: 604-699-7318  
Fax: 604-699-7229  
E-mail: janet.fraser@bctc.com

30 April 2010

Ms. Erica Hamilton  
Commission Secretary  
British Columbia Utilities Commission  
900 Howe Street, Sixth Floor  
Vancouver BC, V6Z 2N3

Dear Ms. Hamilton:

Re: British Columbia Transmission Corporation (BCTC)  
Application for a Certificate of Public Convenience and Necessity (CPCN)  
for the Columbia Valley Transmission (CVT) Project  
Project 3698591  
Responses to Commission Information Request No 2 (IR-2) and Intervenors IR-1

BCTC hereby files its responses to Commission IR-2 and Intervenors IR-1. Responses to confidential IRs are being filed separately, on a confidential basis, with the Commission.

Sincerely,

Original signed by

Janet L. Fraser  
Director, Regulatory Affairs
2.73.0 Reference: Exhibit B-3, BCUC Information Request 1A.1.3
Earned Value

2.73.1 What is the estimated percentage cost of implementing earned value analysis of the CVT project?

RESPONSE:

BCTC has not calculated the cost of implementation as a percentage of project cost. However, BCTC submits that the cost to implement earned value reporting would be material. Further, in BCTC’s view, implementation would provide no additional value in the context of the CVT Project.

The cost of implementing earned value reporting was discussed in BCTC’s response to BCUC IR 3.122.1 in the CVI proceeding (copy attached). Implementing earned value reporting would require BCTC to incur additional costs and increase the costs of BCTC’s contractors and service providers. Implementation would require a substantial amount of work up front to establish data requirements, reporting formats, baseline task descriptions and related internal cost or cash flow forecasts independent of the contract pricing provisions.

Earned value reporting is a tool for monitoring the performance of parties operating under a time and materials contract. Under fixed price contracts, the burden of ensuring efficient use of time, materials and human resources lies with the contractor. By insisting on reporting those parameters, a project proponent risks engaging directly in the management of the contractor’s obligations and, in doing so, undermining the legal and economic protection of the fixed price.

The utility of earned value reporting has been canvassed by the Commission on several occasions. In the proceeding addressing BCTC’s Application for a Certificate of Public Convenience and Necessity for the Interior to Lower Mainland Transmission Project, the Commission canvassed the issue in the IR process and ultimately concluded in its Decision (Order C-4-08, 5 August 2008, page 103) as follows:

“The Commission Panel finds that the content of the quarterly report proposed by BCTC to be adequate and sees no reason to require it to implement earned value reporting.”

BCTC submits that quarterly reporting in the form used in previous projects has and will provide adequate information on project status, cost, schedule and risks. Given this, BCTC does not believe that the costs of implementing earned value reporting should be visited upon BCTC, its contractors or ratepayers.
3.122.0 Reference: Exhibit B-6-1, BCUC IR 1.61.2
Earned Value Reporting

3.122.1 Provide an estimate of any increase in cost in implementing earned value reporting.

RESPONSE

As stated in a number of IR responses, BCTC does not intend to use earned value reporting for the CVI Project. BCTC's existing project reporting methods provide better project management information at a lower cost. The Commission accepted BCTC's position as it relates to earned value reporting explicitly in its August 2008 Decision on the ILM Project, where it determined (page 103) that the contents of the quarterly reporting proposed by BCTC to be adequate and saw no reason to require BCTC to implement earned value reporting. Furthermore, it is BCTC’s opinion that the decision on which project management reporting tools to use is appropriately made by BCTC and should not be determined in a regulatory proceeding.

As discussed in BCTC’s response to BCUC IR 2.79.2, implementing earned value reporting would require BCTC to incur additional costs to hire at least one additional staff and would create an additional administrative burden in extracting, compiling and analyzing data. It would also increase the costs of BCTC’s contractors and service providers, likely increasing bid prices. It would require BCTC to modify the terms of its procurement documents and contracts to require contractors to provide the information in a particular format. It would require a substantial amount of work up front to establish data requirements, reporting formats, baseline task descriptions and related internal cost or cash flow forecasts independent of the contract pricing provisions. BCTC would have to perform manual data collection and data conversion or direct data input to a reporting tool.

BCTC submits that the cost to implement earned value reporting would be material and, in BCTC’s view, would provide no additional value, as discussed in BCTC’s response to BCUC IR 3.122.3. As discussed in response to BCUC IR 2.79.2, BCTC intends, as most others in the utility industry do, to use percent complete assessments, milestones reached and completed pay items as direct measurements of progress and schedule performance. BCTC will use pre-bid cost estimates, tender results, fixed price contract commitments, payments to date and executed or pending change orders in measuring cost performance and in projecting BCTC cash flows and final capital costs. A detailed discussion on BCTC’s preferred project management methodology is included in BCTC’s response to BCUC IR 2.106.1.

For reporting purposes on the CVI Project, BCTC intends to follow the same reporting as on the VITR Project, which is also what was approved by the Commission for reporting purposes on the ILM Project. A copy of the most recent VITR progress report is attached as an example of the reporting for the CVI Project that BCTC will follow. BCTC submits that the format of project reporting it currently follows with respect to the VITR Project provides adequate information for the Commission on the project status, cost, schedule and risks and is produced through its current reporting systems and capital project...
management processes. As such, BCTC believes that it would be inappropriate for BCTC to incur the added cost of earned value reporting on the CVI Project, its contractors, or rate payers, when it is not necessary. BCTC believes that to do so would not be in the public interest.
2.74.0 Reference: Exhibit B-3, BCUC Information Request 1A.1.3
Definition Phase

BCTC states “BCTC estimates that approximately 95% of definition engineering is complete. No implementation engineering has been done.”

2.74.1 If the percentage complete is 95%, provide a breakdown of the total cost to complete the definition phase and include the amounts of IDC costs and overhead attracted.

RESPONSE:

Please see BCTC’s response to BCUC IR 2.109.1.
2.75.0 Reference: Exhibit B-3, BCUC Information Request 1A.1.6.1
Significant Uncertainty

2.75.1 As the total % rate impacts can vary between 3.61% and 4.98%, please define significant uncertainty and quantify significant uncertainty in terms of a range of cost variance in percentage of total project costs.

RESPONSE:

The forecast impact of the preferred alternative as shown in Table 5-6, page 86 of Exhibit B-1 is 3.01% on the Transmission Revenue Requirement and 0.60% on the BC Hydro Revenue Requirement. The latter effectively includes the Transmission Revenue Requirement impact. The two percentages are not additive as seems to be the suggestion in the question.

In BCTC’s response to BCUC IR 1A.1.6.1, BCTC used the term “significant uncertainty” with respect to public interest and not cost per se. For the reasons discussed in BCTC’s response to BCUC IR 1A.1.6.1, BCTC does not believe a public interest threshold can be defined as suggested.
Reference: Exhibit B-3, BCUC Information Request 1A.2.3
BC Hydro Engineering Services Monthly Progress Report

Provide a typical copy of the BC Hydro Engineering Services Monthly Progress Report.

RESPONSE:

Please see attached a template of BC Hydro Engineering Services Monthly Progress Report.
Name of the Project (ENG Project No. XX)
Reporting Period / Month
For the period XX to XX

Project Start Date / Latest Approved In-Service Date

Key Project Personnel
  o Engineering Services Manager
  o Project Tech./Support
  o Transmission Design Lead
  o Substation Design Lead
  o Other Design Leads

Safety Reports

Environmental Incidents

First Nations Issues

Project Highlights / Milestones Achieved

Upcoming Project Milestones

Project Cost Variance

Project Progress

  Specific work group achievements/issues from this reporting period:

Project Management

Engineering Design

  Overhead Transmission

  Transmission Civil, Mechanical and Electrical

  Stations Planning and Design

  Telecommunications Planning and Design

  Protection and Control Planning and Design

Procurement

Construction Contract Management

Testing and Commissioning

Survey and Photogrammetry

Properties
  o For CVT Project - This task reports directly to BCTC.
Regulatory
  o For CVT Project - This task reports directly to BCTC.

Public Affairs
  o For CVT Project - This task reports directly to BCTC.

Legal
  o For CVT Project - This task reports directly to BCTC.

Aboriginal Relations and Negotiations
  o For CVT Project - This task reports directly to BCTC.

Forestry Services

Major Concerns / Risk Assessment
Issue # 1:
  Impact:
  Risk:
  Mitigation:

Change Log
Change Notice #1
  Subject :
  Change : Scope/Schedule/Cost

Other
2.77.0 Reference: Exhibit B-3, BCUC Information Request 1A.2.4
BC Hydro Construction Manager Weekly Progress Report

2.77.1 Provide a typical copy of the BC Hydro weekly progress report.

RESPONSE:

Please see attached a template of BC Hydro Weekly Progress Report.
CONSTRUCTION CONTRACTS DEPARTMENT

[Insert Project Name]

RFP No. 300XXX

WEEKLY REPORT XX
PERIOD: Day Month (Monday) to Day Month (Sunday) Year

Distribution:

[Insert Names]

Submitted by: [Insert Name]

Date: Day Month Year
[Insert Project Name]
Weekly Report #XX

Contractor: [Insert Contractor Name]  Prime: [Insert Contractor Name]  Date: Day Month Year
Sub: [Insert Contractor Name]  Prepared By: [Insert Name]

1. CONTRACT DATES

<table>
<thead>
<tr>
<th>Description</th>
<th>Contract</th>
<th>Forecast</th>
<th>Actual (on Site)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start</td>
<td>Day Month Year</td>
<td>Day Month Year</td>
<td>Day Month Year</td>
</tr>
<tr>
<td>Completion</td>
<td>Day Month Year</td>
<td>Day Month Year</td>
<td>Day Month Year</td>
</tr>
</tbody>
</table>

2. EXECUTIVE SUMMARY-SCHEDULE/PROGRESS

<table>
<thead>
<tr>
<th>SCHEDULE</th>
<th>[Insert Text Here]</th>
</tr>
</thead>
<tbody>
<tr>
<td>PROGRESS</td>
<td></td>
</tr>
<tr>
<td>Submittals</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Site Safety</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Survey</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Civil Work</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Electrical Work</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>P&amp;C Work</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Commissioning</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Equitable Adjustments</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Other</td>
<td>[Insert Text Here]</td>
</tr>
</tbody>
</table>

3. SIGNIFICANT EVENTS AND CONCERNS

<table>
<thead>
<tr>
<th>#</th>
<th>ITEM</th>
<th>DESCRIPTION</th>
<th>ACTION BY</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Submittals</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>2</td>
<td>Site Safety</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>3</td>
<td>Survey</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>4</td>
<td>Civil Work</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>5</td>
<td>Electrical Work</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>6</td>
<td>P&amp;C Work</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>7</td>
<td>Commissioning</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>8</td>
<td>Equitable Adjustments</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
<tr>
<td>9</td>
<td>Other</td>
<td>[Insert Text Here]</td>
<td>---</td>
</tr>
</tbody>
</table>

4. UPCOMING EVENTS

1 [Insert Text Here]
2

5. BCTC SUPPLIED EQUIPMENT AND MATERIAL

1 [Insert Text Here]

6. CONTRACTOR SUPPLIED EQUIPMENT AND MATERIAL

1 [Insert Text Here]
7. CONTRACTOR MANPOWER AND EQUIPMENT

1. [Insert Contractor Name]: 

2. [Insert Subcontractor Name]: 

3. First Nations Involvement: 

8. SAFETY ACTIVITIES - CONTRACTOR STATISTICS

<table>
<thead>
<tr>
<th>Contractor</th>
<th>Medical Aid</th>
<th>Lost Time</th>
<th>Total Time Lost</th>
<th>Site Audits Completed (total)</th>
<th>Compliance Issues</th>
<th>Resolved Compliance Issues</th>
<th>Hours worked by contractor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

INCIDENTS

<table>
<thead>
<tr>
<th>Type (MA or LT)</th>
<th>Date of Incident</th>
<th>Date Reported</th>
<th>Incident Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>None to report</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

9. ENVIRONMENTAL ACTIVITIES

1. [Insert Text Here]

10. COMMISSIONING

1. [Insert Text Here]

11. QUALITY ASSURANCE

1. [Insert Text Here]

12. OTHER

1. [Insert Text Here]

13. PROGRESS PAYMENTS

<table>
<thead>
<tr>
<th>#</th>
<th>PPE DATE</th>
<th>PPE AMOUNT (excluding GST)</th>
<th>% Complete (by $$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>[Insert Text Here]</td>
<td>[Insert Text Here]</td>
<td></td>
</tr>
</tbody>
</table>

14. WORK CHANGE PROGRESS PAYMENTS

<table>
<thead>
<tr>
<th>#</th>
<th>WCPPE DATE</th>
<th>WCPPE AMOUNT (excluding GST &amp; Holdback)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>[Insert Text Here]</td>
<td>[Insert Text Here]</td>
</tr>
</tbody>
</table>

15. EQUITABLE ADJUSTMENTS (to date)

<table>
<thead>
<tr>
<th>EA#</th>
<th>Description</th>
<th>Estimated Amount</th>
<th>Final Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>[Insert Text Here]</td>
<td>[Insert Text Here]</td>
<td>[Insert Text Here]</td>
</tr>
<tr>
<td>Total =</td>
<td></td>
<td>Council</td>
<td></td>
</tr>
</tbody>
</table>
16. COST

**Contract:**
Contract Amount: $ [Insert Text Here]

**Construction Management:**
*Construction Task XXXX*
Forecast Amount: $ [Insert Text Here]
Cost to Date: $ [Insert Text Here]

Forecast Final Amount (includes Estimated EA amount from above)
$ [Insert Text Here]

PHOTOGRAPHS

[Insert Photos Here]
2.78.0 Reference: Exhibit B-3, BCUC Information Request 1A.3.2
Definition Phase

The high-level estimate breakdown is as follows:

1. **Definition Cost:** $4.500M
   - Definition Cost Overhead: $0.135M (based on ISD of 31 October 2012)
   - Definition Costs IDC: $1.079M (based on ISD of 31 October 2012)
   - **Total Loaded Definition Cost:** $5.714M

2.78.1 Please explain the differences between the dates and amounts when compared to the IR response 1.39.1 - CVT Project - Cost Forecast.

**RESPONSE:**

The difference between definition phase cost as stated above and as stated in row 10, column b of table CVT Project – Cost Forecast in BCTC’s response to BCUC IR 1.39.1, is due to rounding error. The estimated definition phase cost for the CVT Project is $4.5M excluding overhead and IDC.

There is no difference in the in-service date of the project as stated in responses to both IRs. Note that the in-service date of October 2012 occurs in F2013, hence some IDC costs are reflected in the F2013 fiscal year.
2.79.0 Reference: Definition Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

2.79.1 This is not actually correct. G-69-07 approves the projects and programs listed in the TSCP F08-F17 Application. In that Application, the Golden System Reinforcement project’s Definition Phase was estimated at $2.5m (page 111). It is Order 107-08 that has approved $3m for the Definition Phase. Please confirm.

RESPONSE:

BCTC confirms the correction to the Order number.
2.79.0 Reference: Definition Phase budgeted costs
    Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

2.79.2 Please provide the reference in G-69-07, the Reasons for Decision, and the Application that approved the definition phase expenditures totaling $3 million.

RESPONSE:

As acknowledged in BCTC’s response to BCUC IR 2.79.1, the reference should be to Order G-107-08.
2.79.0 Reference: Definition Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

2.79.3 Please confirm whether there were any costs actually incurred during F2009 for this project, including any deferral account accruals.

RESPONSE:

BCTC confirms that costs were incurred during F2009 for this project and that there were no deferral account accruals.
2.79.0 Reference: Definition Phase budgeted costs
   Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

2.79.4 Since no breakdown of costs was provided in BCUC 1.39.1 for the $3 million initial estimate of the Definition Phase, please provide the source of the $3 million budget.

RESPONSE:

Please refer to BCTC’s response to BCUC IR 1A.1.1.

The initial $3 million budget was based on a percentage (4%) of the estimated cost for this project at that time.
2.79.0 Reference: Definition Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

2.79.5 Please confirm that the Definition Phase estimate is now currently $5.7 million as opposed to $4.5 million in the Application dated January 22, 2010.

RESPONSE:

As explained in Exhibit B-1 at Appendix I, page 3 (also extracted in BCUC IR 2.78.1) the difference between $4.5 m and $5.7 m is IDC and overhead costs. The project cost shown in Exhibit B-1 at Table 5-3, page 80, shows $4.5 m and the total IDC and overhead are shown as separate line items.
Reference: Definition Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

Should ratepayers continue to expect the Definition Phase cost estimate to continually increase? What are some reassurances that BCTC can provide to ratepayers of the degree of accuracy of these forecasts and the prudence of the costs included?

RESPONSE:

Please see BCTC’s response to BCUC IR 1A.1.1.

The definition phase costs for this project are within (and on the lower side of) the range for such projects.

Engineering and associated inputs must be expended to improve the accuracy of estimates consistent with estimating methodology. This applies to project costing generally, including definition phase estimates. While the initial definition phase estimates are based on a ‘rule of thumb’ percentage of similar scale projects, some effort, such as environmental overview, preliminary design investigation, etc., must be expended to improve such estimates. These activities occur during the definition phase of the project.

Definition spending culminates in the submission of a CPCN Application, which substantially embodies project definition efforts to the date of filing. Exhibit B-1 reflects the total cost of the project including project definition.
Reference: Definition Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.1, 1A.1.1, 1A.1.2

Commission Order G-69-07 approved $2 million in F2009 and $0.5 million in F2010 for the Definition Phase of the Golden System Reinforcement project.

BCTC states “Definition phase expenditures totaling $3 million were approved in the Commission’s Order No. G-69-07.”

Please explain whether the original $3m forecast for the Definition Phase includes IDC, overhead and contingency. If not, please explain why was this excluded in the original forecast?

RESPONSE:

The original estimate of $3 million included capital overhead and IDC.
2.80.0 Reference: Implementation Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.3, 1.39.4

In BCTC’s F2008-F2017 Transmission Capital Plan application, the Golden reinforcement project’s cost estimates for the Implementation Phase was $49.9 million.

In BCTC’s F2009-F2018 Transmission Capital Plan application, the Golden reinforcement project’s cost estimates for the Implementation Phase was $75.0 million.

In this CPCN Application, the Implementation Phase costs are forecast to be $110 million (forecast accuracy of -15%/+35%) (Table 5-3, p. 80)

2.80.1 What is BCTC’s confidence level that the final costs of this project will be within the -15%/+35%?

RESPONSE:

As a project develops and becomes more defined for both scope and schedule, the confidence increases. At this stage of the project with feasibility level designs complete and schedules understood BCTC is confident the estimating methodology detailed in Exhibit B-1, Appendices J and K, reflects an accuracy of -15%/+35%.

Prior estimates were produced at an early planning stage prior to the project definition phase. They reflect preliminary information available at that and prepared at a much lower accuracy level without the benefit of a Monte Carlo analysis.

Please refer to BCTC’s response to BCUC IR 1.53.3.
2.80.0 Reference: Implementation Phase budgeted costs
Exhibit B-3, BCUC 1.1.1.1, 1.39.3, 1.39.4

In BCTC’s F2008-F2017 Transmission Capital Plan application, the Golden reinforcement project’s cost estimates for the Implementation Phase was $49.9 million.

In BCTC’s F2009-F2018 Transmission Capital Plan application, the Golden reinforcement project’s cost estimates for the Implementation Phase was $75.0 million.

In this CPCN Application, the Implementation Phase costs are forecast to be $110 million (forecast accuracy of -15%/+35%) (Table 5-3, p. 80)

2.80.2 How many BCTC projects completed in the last 10 years are within the -15%/+35% range? How many are outside of this range?

RESPONSE:

BCTC has been responsible for transmission system capital planning since F2006. In the context of projects comparable to CVT, BCTC has completed two CPCN projects, the System Control Modernization Project (SCMP) and the Vancouver Island Transmission Reinforcement Project (VITR) and is forecasting to complete the Central Vancouver Island Project (CVI) during F2011. The table below summarizes the estimated and actual expenditures for these projects.

<table>
<thead>
<tr>
<th>$ millions</th>
<th>In-Service Date</th>
<th>Estimated</th>
<th>Actual</th>
<th>Change $</th>
<th>Change %</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCMP</td>
<td>Mar 08</td>
<td>133</td>
<td>129</td>
<td>(4)</td>
<td>-3%</td>
</tr>
<tr>
<td>VITR</td>
<td>Dec 08</td>
<td>249</td>
<td>306</td>
<td>57</td>
<td>23%</td>
</tr>
<tr>
<td>CVI</td>
<td>Oct 10</td>
<td>91</td>
<td>91</td>
<td>-</td>
<td>0%</td>
</tr>
</tbody>
</table>

The question is being addressed on a broader scale in BCTC’s current Application for F2011 Rates (see BCTC’s responses to BCUC IRs 1.5.1, 1.7.1, and 1.16.1).
2.81.0 Reference: Exhibit B-3, BCUC 1.2.4
Sole Sourcing of Engineering Resources

2.81.1 Please describe how the “hand-off” will occur from BC Hydro Engineering Services to BCTC material procurement. For instance, please confirm the process and whether BC Hydro or BCTC personnel actually perform the following functions:

a) material take-off from design

b) request for bids and selection of material supplier

c) confirmation of materials received against specifications and material ordered

RESPONSE:

As stated in BCTC’s response to BCUC IR 1.2.4, BCTC will be responsible for material procurement and construction.

BC Hydro Engineering Services will provide the scope and specifications of requirements to BCTC Procurement along with design drawing for the material take-off.

Depending on the complexity and requirements, BCTC will issue either a Request for Proposal (RFP) or a Tender to procure the material. All proposals/bids will be received by BCTC.

An evaluation team will be formed which will generally include the Project Manager (BCTC), Safety Manager (BCTC), Procurement Lead (BCTC), Engineer on Record (BCH), Quality Assurance Lead (BCH) and Construction Manager (BCH). Based on this evaluation and the recommendation of the evaluation team, subject to approval of the Project Manager, BCTC will award the contract for the material.

For some major equipment such as power transformers, there are existing BCTC multi-year standing purchase orders. Equipment covered under these purchase orders will be procured accordingly. In this case, the Engineer on Record (BCH) will provide the requirements to BCTC Procurement and upon approval from the Project Manager (BCTC), the purchase order will be issued.

All miscellaneous material and equipment will be supplied and installed by the general construction contractors. In these instances, the material take-off from design will also be the general construction contractors’ responsibility.
All materials will be delivered to site and will be received by general construction contractors on behalf of BCTC. The general construction contractors will provide confirmation of material received against specification and material order.

Please also refer to BCTC’s response to BCUC IR 1A.2.11.
2.82.0 Reference: Exhibit B-3, BCUC 1.4.1
Actual Winter Peak

2.82.1 For the hour in which each substation experienced the measured peak shown in the referenced response, please provide the coincident measured peak of the other four substations. Please also provide the coincident measured peak of all five substations, all for the 2009-2010 winter season.

RESPONSE:

The coincident measured peaks for four substations based on coincidence with the peak load at a fifth substation are not available due to the limitations in the metering facilities at the substations and BCTC’s real-time EMS (Energy Management System) and PI (Plant Information) system.

Similarly, the coincident measured peak loads at the five substations in the upper Columbia Valley are not available. However, the total coincident measured peak load for all five substations is available based on data provided by the EMS/PI system at Invermere substation for 60L271. Based on the recorded data, the total peak load for the five substations in 2009/10 neglecting the load displaced by Spillamacheen generation (typically 1 MW (or less) during the winter peak load period due to watershed freeze-up) suggesting an average coincidence factor of 0.92 based on the total of the individual substation winter peak load forecasts.

It should be noted that although the load at all five substations in the upper Columbia Valley contribute to the voltage limitations and supply capacity constraints encountered in the upper Columbia Valley 69 kV system, the critical load is the Golden load being the largest load in the system and located at the end of the transmission system, the weakest, most sensitive, critical location in the system in regards to the voltage constraints encountered. Consequently, the peak load at Golden and its resultant voltage levels are the principal issues driving the need for system reinforcement in the upper Columbia Valley area.
2.83.0  Reference:  Exhibit B-3, BCUC 1.5.1, 1.5.2
60L271 INV-GDN 69 kV Transmission Constraints

2.83.1  Please identify and describe the amount of voltage stability margin available above 29 MVA between stable operation and system collapse, and state the assumptions applicable to the identified voltage stability margin(s).

RESPONSE:

According to system analysis, there is virtually no voltage stability margin available above 29 MVA. The power flow solution diverges and does not solve under most N-1 contingency conditions if the load at Golden exceeds 29 MVA.

Please see planning study assumptions set-out in Exhibit B-1, Appendix B, page 17.
2.83.0 Reference: Exhibit B-3, BCUC 1.5.1, 1.5.2
60L271 INV-GDN 69 kV Transmission Constraints

2.83.2 Please provide examples specific to 60L271 of the following contingencies that could lead to system collapse when 29 MVA is being delivered to GDN:

a) system disturbance (disturbances on a radial line that would not otherwise interrupt service)

b) sudden load variation (which loads not already on-line), and

c) change in system condition (that would not otherwise interrupt service).

RESPONSE:

When approximately 29 MVA is being supplied to GDN, system disturbances, such as sudden system disturbance, load variation or change in system condition in the upper Columbia Valley radial transmission system would not lead to a system voltage collapse.

Above 29 MVA supply system disturbances such as loss of SPN generation, loss of GDN shunt capacitor banks or INV shunt capacitor banks may lead to system instability.
2.83.0 Reference: Exhibit B-3, BCUC 1.5.1, 1.5.2
60L271 INV-GDN 69 kV Transmission Constraints

2.83.3 Please provide the range of the voltage on the 69 kV side of the transformers that the GDN 69/25 kV transformer LTC’s are capable adjusting for to maintain rated distribution bus voltage level at full load, and provide the 60L271 line voltage range at GDN when supplying 29 MVA.

RESPONSE:

When supplying 29 MVA at 0.98 p.f., the voltage range at GDN provided by 60L271 would be 60 kV to 63.4 kV depending on the status of the system, for both normal operation and contingency conditions. (Note the transformer LTC is capable of operating at 59.9 kV to 77 kV on high-side.)
2.84.0 Reference: Exhibit B-3, BCUC 1.7.1
INV 230/69 kV Transformer Constraints

2.84.1 Please provide the normal and emergency ratings for summer and winter for the INV 230/69 kV transformers.

RESPONSE:

Ratings for the INV 230/69 kV system transformers are:

(a) Normal, 84 MVA based the transformer’s nominal rating; and

(b) Maximum (winter), 106.5 MVA based on a real-time rating review.
2.85.0  Reference:  Exhibit B-3, BCUC 1.7.1
GDN 69/25 kV Transformer Constraints

2.85.1  Please provide the normal and emergency ratings for summer and winter for all the transformers at GDN.

RESPONSE:

Ratings for the INV 230/25 kV distribution transformers are:

(a) Normal, 25 MVA in summer and 29.7 MVA in winter based the transformer’s maximum nominal rating;

(b) Emergency, 29.2 MVA in summer and 35.1 MVA in winter based on a real-time rating review under winter conditions.
2.86.0 Reference: Exhibit B-3, BCUC 1.10.1

2.86.1 Please describe the realistic expectations that Smart Meters will have on the overall electric system and identify any utilities that have had favorable results, if none can be identified, please explain why Hydro is gambling on immature technology at ratepayers’ expense.

RESPONSE:

This question was forwarded to BC Hydro for response. The following is BC Hydro’s response:

BC Hydro takes issue with the tone of the information request, and questions the relevance of utility industry experience of smart metering to the review of BCTC’s Columbia Valley Transmission (CVT) Project.

With that said, with respect to BC Hydro’s expectations for the impact of smart metering on its overall electric system, BC Hydro notes that in addition to the time required to install the smart meters and related equipment and put them into operation, time of use and/or critical peak pricing rate structures will also need to be implemented before capacity savings can be achieved on the overall electric system. For this reason BC Hydro does not believe it would be prudent to defer or cancel the CVT project based on an expectation of timely capacity savings in the Columbia Valley area due to smart metering.
2.87.0  Reference:  Exhibit B-3, BCUC 1.14.1

2.87.1  Please provide a cost estimate of replacing the 138 kV line alternative from Mica with a 230 kV line. Include a loss calculation.

RESPONSE:

The cost of Alternative 3 with a 230 kV transmission line is estimated to be $304 million. This estimate has an accuracy of -50%/+100% and includes contingency, inflation, BCTC corporate overhead and IDC.

Transmission system losses

<table>
<thead>
<tr>
<th>(MW)</th>
<th>2012/13</th>
<th>2025/26</th>
<th>2038/39</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternative: MCA-Golden 230 kV line</td>
<td>0.53</td>
<td>0.92</td>
<td>1.86</td>
</tr>
</tbody>
</table>
2.88.0  Reference: Exhibit B-3, BCUC 1.14.2

2.88.1  Re: (g) response- if a 25 kV express bus feeder was connected to the low site of the 69/25 kV transformer(s) how much back feed capacity would be available to supply 60L271 South from GDN?

RESPONSE:

Without considering the technical disadvantages identified in BCTC’s response to BCUC IR 1.14.2, this configuration assuming an impractically large conductor is installed on an express 25 kV feeder between KHS and GDN to supply both (a) the GDN load directly at 25 kV from KHS and (b) additional 60L271 load by back-feeding 60L271 using the GDN transformers to step-up to the 69 kV voltage level. In this scenario, based on the load forecast, maximum backfeed capacity would occur in winter 2026/2027 and would be 68.5 MVA from GDN to RDM (which includes 47.7 MVA at GDN, 17.4 MVA at RDM, and 3.4 MVA at PSN/SPN).
2.89.0  Reference:  Exhibit B-3, BCUC 1.14.2

2.89.1  Re: (h) response- Not if the IPP was connected at 230 kV as described in the ultimate layout for KHS - correct?

RESPONSE:

Correct, additional transformation would not be required at KHS if the IPPs were interconnected at the 230 kV voltage level.
2.90.0 Reference: Exhibit B-3, BCUC 1.14.3

2.90.1 Please update the cost estimate for the preferred option using a double circuit tower design with only 1 circuit installed. Would this not be a viable option covering unforeseen load growth necessitating another line and ROW?

RESPONSE:

The cost estimate for a double circuit 230 kV transmission line using steel H-frame tower design with only one circuit installed, is $207M. This estimate includes all substation work and the 69 kV transmission line from KHS to Golden and contingency, overhead, IDC and inflation. Estimate accuracy is -50% to +100%.

BCTC does not consider constructing a double circuit 230 kV transmission line with only one circuit installed as a viable option. As stated in BCTC’s response to BCUC IR 1.14.3, based on the planning studies, a single circuit 230 kV transmission line will exceed the capacity required to meet the load growth requirements for the Golden area and the Columbia Valley for the next 30 years (planning cycle for the project).
2.90.0  Reference:  Exhibit B-3, BCUC 1.14.3

2.90.2  Please provide a cost estimate of acquiring additional ROW now to accommodate a future separate line, if required as was done on (for example) the Jordan River 138 kV line i.e. doubling the ROW width requirement for the proposed 230 kV line from INV to GDN to allow for future growth beyond the planning period.

RESPONSE:

BCTC is currently proposing to acquire a 40 m wide right-of-way based on single circuit 230 kV using standard wooden H-frame structures. The cost to acquire this corridor will be approximately $325,000.

To construct a second single circuit 230 kV using standard wooden H-frame structures adjacent to the proposed 230 kV, BCTC would require an additional 25 m right-of-way. The cost for this additional right of way would be approximately $205,000.

The above costs do not include costs for additional First Nations and Public consultation.
2.91.0 Reference: Exhibit B-3, BCUC 1.14.4

2.91.1 Please explain how the joint pole use arrangement with Telus is any different?

RESPONSE:

BC Hydro’s joint pole use agreement with Telus relates to shared use of structures for telecommunication and distribution facilities. BCTC is not a party to this arrangement.

Considerations related to technical, operational and safety parameters, as noted in BCTC’s response to BCUC IR 1.14.4, would substantially differ for double circuiting transmission facilities as compared to shared use between telecommunications and power distribution facilities.
2.92.0 Reference: Exhibit B-3, BCUC 1.14.5

2.92.1 Re: (d) Please explain why 60L271 SPN-GDN section was upgraded to 138kV - what were the plans at the time to justify the expense? Please explain.

RESPONSE:

The section of 60L271 between SPN and GDN was never upgraded to 138 kV, it was constructed in the 1960s to 138 kV standards and operated at 69 kV since that time. The 69 kV system to SPN was built prior to the 1960s.

At this time, BCTC is not aware of the reasoning to construct the SPN-GDN section of the 69 kV radial system to 138 kV standards.
2.92.0  Reference:  Exhibit B-3, BCUC 1.14.5

2.92.2  Please explain if converting GDN substation to 138/25 kV is feasible on the present footprint and if necessary the adjacent property owned by B.C. Hydro. Do not consider any additional line terminations in the response i.e. 60L271 converted to 138kV would be the only radial feed to GDN.

RESPONSE:

Converting GDN substation to 138/25 kV using a standard air-insulated, low profile configuration, is not feasible on the present footprint and using the adjacent property owned by BC Hydro.

Converting GDN substation to 138/25 kV is feasible by utilizing 138 kV Gas Insulated indoor (GIS) switchgear using the adjacent property owned by BC Hydro. Implementing high-cost switch gear would likely not provide savings compared to a new air-insulated switchyard.
2.92.0 Reference: Exhibit B-3, BCUC 1.14.5

2.92.3 Re: (f) response- Could PSN load be served by a GDN 25 kV feeder extension? Would a line VR be required?

RESPONSE:

This question was forwarded to BC Hydro for response. The following is BC Hydro’s response:

Parson substation (PSN) can be served by a Golden (GDN) 25 kV feeder provided that the PSN load is converted to 25 kV and the existing PSN distribution voltage regulator is upgraded to 25 kV.

Serving PSN load from GDN will increase distribution circuit length from 15 km to 62 km, resulting in higher exposure to weather and tree related outages and reduced reliability to existing PSN customers. The addition of line reclosers will mitigate the reliability impact on GDN customers, but will not mitigate the increased outage exposure for PSN customers.
2.93.0 Reference: Exhibit B-3, BCUC 1.14.6

2.93.1 Is it not standard utility practice to upgrade lines with the expectation that some outages will be required? Cannot a large portion of the construction be completed using live-line techniques?

RESPONSE:

It is expected and is standard utility practice that some outages will be required to upgrade transmission lines.

It is not a standard utility practice to construct a high voltage transmission line over long-distance using live-line techniques. Live-line work at transmission voltages requires specially trained, qualified crews and specialized equipment. Techniques require substantial set-up and care and the work is very weather dependant. This approach is generally cost prohibitive for continuous construction work over long line lengths. Transmission system live-line work is generally limited to work at localized areas with limited work scope.
2.93.0 Reference: Exhibit B-3, BCUC 1.14.6

2.93.2 Please explain if the conversion is technically viable on the existing ROW using single pole structures and vertically spaced conductors and describe the effort and provide a cost estimate to acquire additional ROW width – if/where required.

RESPONSE:

In BCTC’s response to BCUC IR 1.14.6, BCTC discussed the challenge of contemplating construction of a 138 kV line on the 69 kV route. While arguably technically viable, in BCTC’s view this is not considered feasible for the reasons stated in the earlier response. Viability would also depend on the ability to acquire adequate clearance and right-of-way.

BCTC cannot provide a reasonable cost estimate to acquire a new right-of-way along the existing 60L271 transmission line. The difficulty in acquiring additional right-of-way is discussed in BCTC’s response to BCUC IR 1.14.7.
2.93.0 Reference: Exhibit B-3, BCUC 1.14.6

2.93.3 Please explain how the SPN-GDN section was upgraded to 138KV in light of this restriction? Is this option technically possible on the existing ROW using single pole structures? If not, why not? Did BCTC have discussions with MOT on this option? If not - why not, please explain. Please do not restate any of the rationale already submitted.

RESPONSE:

The town of Golden was supplied by diesel generators until the time this existing SPN-GDN transmission line was constructed. This line was originally constructed to applicable 138 kV standards and was never upgraded

Please see BCTC’s response to BCUC IR 2.93.2. BCTC did not discuss this option with MOTI.
2.94.0 Reference: Exhibit B-3, BCUC 1.14.7, 1.54.3
Overview of Supply Alternatives

2.94.1 Did BCTC consider the option of:

1) At INV add two 230/138 kV Xfmr(s), a 69 kV line termination and a 138 kV line termination.

2) A double circuit line built to 138 kV standards on the proposed new corridor between INV and SPN with one circuit operated at 69 kV, dropped off and terminated at SPN.

3) The new 138 kV line from INV to SPN would tie into 60L271 converted to 138 kV from SPN to GDN.

4) At GDN convert 69 kV line termination to 138 kV, change 69/25/12 kV Xfmr(s) to 138/25 Xfmr(s), accelerate completion of voltage conversion to eliminate 12 kV and extend a 25 kV distribution feeder to PSN (a line VR may be required).

5) AT PSN eliminate the substation.

6) At SPN add new 69 kV line termination, replace Xfmr(s) with 69/25/12 kV Xfmr(s) from GDN, and build 25 kV feeder to PSN to supply from 2 sources. Install 138 kV line switch to tie old 60L271 South to RDM, to Northbound to GDN 60L271 converted to 138 kV.

If not, why not? Please discuss issues other than long customer outages required for construction and no N-1 line contingency available to supply GDN.

RESPONSE:

The development outlined above is a variation of the 138 kV option in which the existing 138 kV-rated section of 60L271 between SPN and GDN would be cut and tied to a new 138 kV transmission line from INV to SPN (refer to Exhibit B-1, Appendix B, page 60). That option was dismissed for a number of reasons.

The primary difference between these options is as follows:
(a) The proposal above replaces the new INV-SPN 138 kV transmission line with a double-circuit 138 kV transmission line.

(b) It adds a new 69 kV line terminal at INV for a 69 kV circuit that would be installed in one of the line positions on the new double-circuit structures.

(c) It upgrades SPN significantly based on the replacement of the 13.8/25 kV distribution transformer with a 69/25 kV transformer from GDN, the addition of a new 69 kV line terminal and the installation of a 138 kV disconnect switch to tie the remaining section of 60L271 (SPN-INV) to the new INV-GDN 138 kV circuit at SPN.

(d) It upgrades GDN to a 138 kV substation.

In regards to the above proposal:

(a) Conversion of GDN to 138 kV was considered previously, in particular with the 138 kV transmission line option from INV to the Golden area, but was dismissed due to site constraints at GDN and constructability issues within the substation.

(b) Retirement of PSN was considered previously as part of the original 60L271 SPN-GDN upgrade option for 138 kV operation but was dismissed due to the degradation in the reliability of supply that would be incurred by the Parsons area customers due to distribution only supply from SPN. As a general principal, whenever upgrading a system, any degradation in the quality of power supply to customers is avoided as much as possible.

(c) The development of a 69 kV loop between from INV to SPN and back to INV via RDM and ATH would be difficult to justify based on (i) the additional cost of the double-circuit transmission line between INV and SPN plus the line terminals at both ends of the line and (ii) the size of the load supplied in this system. ATH is the largest load by far that would be supplied by this loop but it already has backup supply provided by a tap to 60L270 INV-KBY.
2.94.0 Reference: Exhibit B-3, BCUC 1.14.7, 1.54.3  
Overview of Supply Alternatives

2.94.2 Please provide an analysis of the configuration described in the preceding question with the same depth as provided in the response to BCUC 1.54.3. Please provide a high level estimate for this configuration including elimination of the PSN substation and supplying the PSN load from upgraded distribution feeders from both GDN and SPN.

RESPONSE:

BCTC’s response to BCUC IR 1.54.3 focused primarily on a construction sequence that would minimize outage requirements for customers in the upper Columbia Valley during the construction of the option described in BCUC IR 1.54.3 and the feasibility of supplying the PSN load from GDN and SPN. The analysis requested for the option proposed in BCUC IR 1.54.3 was provided primarily in BCTC’s responses to BCUC IR 1.14.5 and BCUC IR 1.14.6. Consequently, an analysis of the configuration described in BCUC IR 2.94.1 with the same depth as provided in the response to BCUC IR 1.54.3 is provided below based on the analysis provided in the responses to BCUC IRs 1.14.5 and 1.14.6:

Reliability of supply to the upper Columbia Valley:

The reliability of supply to the customers supplied by the 69 kV system would be improved due to the development of a 69 kV loop from INV to SPN and back to INV, plus improvement to ATH as marginal as it already has a backup supply from 60L270.

For PSN customers, the reliability of power supply will be degraded by supplying it with two distribution sources compared to that of the CVT Project with PSN supplied by two transmission sources (60L271 SPN-PSN and back feeding from GDN).

Customers in the Golden area, however remain dependent on single-circuit radial supply.

Considering two-circuit supply to Golden under the CVT Project and its backfeeding capability, plus the relative difference in transmission line reliability between high voltage and lower voltage lines, the reliability of supply provided by the proposed configuration is likely lower than that provided by the CVT Project.

Supply capacity:

The supply capability to GDN of the proposed configuration will be lower than that for CVT Project (230 kV) and approximately the same as the 138 kV option described in the planning
report (Appendix B of Exhibit B-1). In comparison to the 230 kV option, it would be less capable of meeting unanticipated load growth in the Golden area beyond the long range planning period.

**System losses:**

The losses associated with the option described above would be higher than the losses associated with the CVT Project (230 kV) and approximately the same as the losses incurred with the 138 kV alternative with the exception that the losses incurred in the 69 kV system would be marginally lower due to the looped 69 kV system.

**GDN and PSN conversion to 138 kV:**

Given the space constraints at GDN, a new 138/25 kV substation would be required in the community of Golden to accommodate the conversion to 138 kV.

While the conversion of PSN to 138 kV would be avoided; the configuration requires up to 68 km of new 25 kV feeder construction.

**Future IPP integration:**

Integrating future IPP developments in the area north of Golden may be limited under the proposed configuration, as compared to the CVT Project, due to GDN substation limitations and the lower capacity of a 138 kV system.

**Cost:**

Cost for the proposed configuration is $138 million, including contingency, overhead, IDC and inflation, and has an accuracy of -50%/+100%.
2.95.0  Reference: Exhibit B-3, BCUC 1.14.9

2.95.1  The response did not address the option of (for greater clarity) a 230 kV line from INV on the proposed new ROW and a new 230/69 kV sub at SPN /PSN area (or some other point downstream of the ATH/RDM load if the footprint of these subs is prohibitive.) This option would have a line breaker connected to 60L271 back South to ATH/RDM and another line breaker North on 60L271 to GDN i.e. essentially locating KHS north of ATH or RDM with a 69 kV ring; perhaps in the SPN/PSN area. This would negate arguments 1.14.5 (a) (b), (c), and (d) and would require minimal outages to tie into the system. Please discuss any remaining arguments without repeating those already explained. How many years would this option serve the planning criteria? Again, the lack of N-1 contingency for GDN is duly noted and need not be repeated.

RESPONSE:

This proposed option would not meet the long term supply requirements for the upper Columbia Valley and was not considered. It would only meet load supply requirements at GDN up to 2020/21.

With respect to references to BCTC’s original response to BCUC IR 1.14.9:

(i) The statement that 230/69 kV option would negate argument (a) is not correct. Customers supplied by the section of the system north of the 230/69 kV substation would still be dependent on single-circuit supply provided by the 69 kV transmission line from the 230/69 kV substation to GDN (as per the 138 kV line under the SPN 230/138 kV option). The proposed CVT Project will provide greater reliability to the customers north of the 230/69 kV substation at SPN.

(ii) The statement that the 230/69 kV option would negate argument (b) is not correct. The supply capacity to the Golden area under the 230/69 kV option would be less than that provided under proposed CVT Project.

(iii) The statement that the 230/69 kV option would negate argument (c) is not correct. The system losses under the 230/69 kV option would be higher than that incurred under the 230 kV option proposed for upper Columbia Valley supply purposes.
The configuration would not have the flexibility or capacity to integrate future IPP developments in the upper Columbia Valley area. Integration under the configuration could require significant system reinforcement between the 230/69 kV substation and Golden.
2.96.0 Reference: Exhibit B-3, BCUC 1.15.1
138kV Transmission Line from Mica to Golden (Alternative 3) Scope Options

2.96.1 Please identify the total peak and average amount of load that would need to be interrupted for the three 69 kV loads identified in the referenced response.

RESPONSE:

The total peak load that would need to be interrupted for the three 69 kV loads identified in the reference response is as follows:

(a) McCullock Creek (MCK) peak load 0.04 MVA
(b) Goldstream Mine (GSM) peak load 0.25 MVA
(c) Goldstream Tap (GST) peak load 0.015 MVA

There is no average load information available for these three substations.
2.96.0 Reference: Exhibit B-3, BCUC 1.15.1
138kV Transmission Line from Mica to Golden (Alternative 3) Scope Options

2.96.2 Has BC Hydro consulted the Ministry of Transportation and Infrastructure and requested permission to place 138 kV structures in the road allowance for either the referenced option or any of the other options (including widening the existing 60L271 right of way) considered in this application. If not, why not?

RESPONSE:

BCTC did consult with the Ministry of Transportation and Infrastructure (MOTI) on routing the 69 kV transmission line from Kicking Horse substation to Golden substation.

BCTC did not consult with MOTI regarding special permission to place 138 kV structures in road allowance. A dedicated right-of-way for higher voltage line is preferable for safe reliable operation and maintenance purposes. Please see BCTC’s responses to BCUC IR 1.14.6 and BCUC IR 1.14.7 for a discussion of the challenges with the suggested approach.
2.96.0 Reference: Exhibit B-3, BCUC 1.15.1
138kV Transmission Line from Mica to Golden (Alternative 3) Scope Options

2.96.3 Please identify the most recent request made by BCTC to the Ministry of Transportation and Infrastructure to place 138 kV structures in a road allowance that was denied.

RESPONSE:

Ministry of Transportation and Infrastructure present policy generally allows electricity infrastructure up to and including 69 kV. New installation of 138 kV transmission lines on road allowance is unusual. High voltage transmission lines, present a number of issues distinct from those that arise with the distribution network. Theses issues include technical and engineering considerations relating to the potential interaction or impact between electricity transmission and highway construction and operation.

BCTC has not made a recent request to place 138 kV structures in the road allowance.
2.97.0 Reference: Exhibit B-3, BCUC 1.15.2
138kV Transmission Line from Mica to Golden (Alternative 3) Scope Options

2.97.1 Does BCTC assert that the construction of a step down substation on 5L71 or 5L72 creates unacceptable system risk, and if so, please discuss how BCTC’s decision making process differentiates “acceptable risks” such as FortisBC’s Vaseux Lake Station or BCTC’s proposed series capacitor stations from the risks of a step down substation that would serve other portions of the system.

RESPONSE:

BCTC did not assert that the construction of a step-down substation in 5L71 or 5L72 would create an unacceptable system risk. BCTC stated that “the construction of step-down substations in these types of lines is avoided as much as possible.” In this particular situation, 5L71 and 5L72 are the only two transmission lines interconnecting Mica Generating Station, one of the major generating stations, to the BCTC transmission system. The loss of these two lines would result in a major loss of system generation with major impacts on the ability of the BCTC system to meet system load supply requirements. This system risk must be minimized and that includes optimally maintaining the integrity of both Mica-Nicola transmission lines. Due to the importance of the two Mica-Nicola transmission lines, it is prudent to consider other more economic and technically feasible options.

BCTC does not have a specific decision making process that differentiates between acceptable risks and unacceptable risks when reviewing the interconnection of a system step-down substation for regional system supply purposes. The decision making process is based on the specific circumstances of the any proposal to construct a step-down substation in a 500 kV transmission line and includes a review of the need for a step-down substation, the alternatives available, and the system risk associated with the development.

As indicated in BCTC’s response to BCUC IR 1.15.2, substations are avoided to preserve the integrity of the bulk transmission system.

Generally, step-down substations constructed in 500 kV bulk transmission circuits are major regional receiving stations used as hubs for regional transmission system supply purposes. These major receiving stations are often bulk transmission terminal stations such as Ingledow or Meridian substations in the Lower Mainland or major receiving stations for regions located between the terminal points of the bulk transmission system, such as Nicola substation, Kelly Lake substation and Ashton Creek substation that supply the South Interior region of the BCTC.
system. Step-down substations can be constructed in more remote areas to supply smaller, more localized load centers where they are the only practical options available for local supply purposes, such as Kennedy substation in the Northern region that is used primarily to supply a small cluster of industrial developments approximately 140 km north of Williston substation in Prince George, the major receiving station for the Central Northern Interior area. However, developments to supply these smaller loads are avoided as much as possible to minimize the risk to the bulk transmission system. In this instance, the substation was justified based on the development being the most feasible option for local area supply purposes and the substation’s connection being made to only one of the three 500 kV transmission lines transmitting generation from the Peace Canyon area to southern BC, thus minimizing the risk to the integration of the generation in the Peace River area.

In regards to series capacitor stations, they are constructed in transmission lines such as 5L71 and 5L72 to maximize the transfer capability of the transmission line. They may reduce the reliability of the transmission line but they are viewed as integral components of the transmission line for load transfer purposes. Generally, the risk associated with series capacitor stations is less than that associated with a step-down substation due to the extensive switching devices and transformation installed in the step-down substation and the potential impact of line or transformer faults on the bulk transmission lines due to breaker failure. The other option available to series capacitor banks is usually to construct additional transmission lines but the cost for these major bulk transmission lines are very high and require the approvals and permits necessary to facilitate their construction including First Nation and environmental issues.

In regards to FortisBC’s Vaseux substation, its development was justified as a major receiving station for supply to FortisBC’s South Okanagan regional transmission system located between Oliver near the BC-USA border and Kelowna in the center of the Okanagan area. Prior to constructing Vaseux substation, this system was supplied by two FortisBC 230 kV transmission lines terminated at BCTC’s Vernon Terminal substation (supplied by 500/230 kV transformation at Ashton Creek substation and two 230 kV transmission lines from Ashton Creek to Vernon) and a very weak tie to the FortisBC’s West Kootenay power system. Because this area has developed into a major load area requiring a high capacity supply system, establishing a major step-down substation in the Vaseux Lake area was the most practical option available for supply to a system of this size and the construction of a 500/230/138 kV step-down substation in the Selkirk-Nicola 500 kV transmission line to supply this system was consistent with BCTC’s general philosophy regarding the development of major regional receiving substations in bulk major transmission lines for that purpose. Further, 5L96 is not a major generation integration circuit and the implications of losing the Selkirk-Nicola tie due to a station fault at Vaseux doesn’t have the same implications regarding system risk as the loss of one of the two 500 kV circuits interconnecting Mica generation to the integrated system. If this tie was to be forced
out of service, there are several other tie circuits available between Selkirk Substation and the southwest portion of the BCTC system, including 5L91 to Ashton Creek Substation plus ties to the USA system at Nelway Substation.
2.98.0 Reference: Exhibit B-3, BCUC 1.17.1
System Losses

2.98.1 Please explain why system losses outside the Columbia Valley do not change for Alternative 3, even though it is potentially off loading 5L71/72 by supplying electricity to GDN.

RESPONSE:

System losses outside the Columbia Valley will change for Alternative 3 due to the off-loading of 5L71/72. However, as per BCTC’s response to BCUC IR 1.17.1, the change in losses are not material.

The insignificance of the change in the losses outside the Columbia Valley is due to the relative small off-loading effect of the GDN load (a maximum of 65 MW) compared to the total load on the system outside the Columbia Valley (approximately 10,000 to 12,000 MW).
2.99.0 Reference: Exhibit B-3, BCUC 1.17.2
Capacity Cost/MVA as a Project Comparator

2.99.1 BCTC states that the cost/MVA helps put the cost of flexibility into perspective, in particular when one option may cost marginally more than another option but provide more capacity to meet unexpected developments or post-long range period load growth. Please explain how this future benefit is discounted or capable of being compared. For instance, does Alternative 2, with a Capacity Cost/MVA of 1.30 provide almost twice the economic benefit of Alternative 3, which has a Capacity Cost/MVA of 2.55?

RESPONSE:

The cost/MVA measure helps to facilitate a comparison of alternatives which provide immediate and long term benefits. In this case the analysis demonstrates that one option provides more capacity to meet both unexpected developments and long range period load growth but which costs marginally more than another option which does not provide these benefits. Though difficult to discount cost benefits, a cost/MVA analysis is particularly helpful when the cost of a transmission project at some future time can be expected to be significantly more to achieve the same benefits than a marginal cost difference between competing alternatives may provide today.

The intent is not to imply that an option with a cost equal to 50% of another option has twice the economic benefit. The assertion that Alternative 2 provides almost twice the economic benefit of Alternative 3 is likely too simplistic.
2.100.0  Reference:  Exhibit B-3, BCUC 1.22.2  
Transmission Expansion Policy ("TEP") Alternatives

2.100.1  Please confirm whether a 230 kV transmission line from MCA to KHS would have sufficient thermal capacity to interconnect both the Goldstream and Beaver River clusters.

**RESPONSE:**

A 230 kV transmission line with a standard conductor, such as 927 MCM 37/0 ASC installed on the existing Cranbrook to Invermere 230 kV transmission line, would have a maximum summer thermal rating of 423 MVA, sufficient to transfer generation in the Goldstream and Beaver River clusters indicated for TEP evaluation purposes.
2.101.0 Reference: Exhibit B-3, BCUC 1.22.3

2.101.1 Does the recently announced selection of Selkirk IPP in the Clean Call for Power relieve any uncertainty to answer the question? Please explain.

RESPONSE:

BCTC believes the Clean Call for Power may inform the expected future size of IPP generation in a region, but does not relieve the uncertainty of IPP development in the region. BC Hydro received 68 proposals in response to the Clean Call for Power of which two projects are located in the Goldstream and Beaver River IPP clusters. The announced selection of Selkirk IPP represents one of 23 projects to be awarded electricity purchase agreements, subject to obtaining necessary permits and reaching commercial operation. If BCTC were to assume that the results of the Clean Call for Power exclusively determine the likelihood of IPP development in a region, the proposals received and announced selection indicate modest IPP development in the Goldstream and Beaver River IPP clusters relative to other areas in British Columbia.
2.102.0 Reference: Exhibit B-3, BCUC 1.24.2
Economic Benefit of Interconnection under the TEP Alternatives

2.102.1 Please explain how the 784 GW.h of energy associated with the Goldstream cluster is being collected in Alternatives 1 and 2 for the purposes of the analysis shown in Exhibit B-1, Table 4-7.

RESPONSE:

TEP Alternatives 1 and 2 exclude economic benefits associated with the integration of the Goldstream area generation. TEP Alternative 3 includes economic benefits from both Beaver River and Goldstream clusters.
2.103.0 Reference: Exhibit B-3, BCUC 1.25.1, 1.26.1, 1.68.1
Net Economic Effect and Revenue Impact Analysis

2.103.1 Please confirm that for 100 percent IPP development, the information in the responses to BCUC 1.25.1 and 1.26.1 appear to show that the net revenue requirement for Alternative 3 is less than Alternatives 1 and 2.

RESPONSE:

BCTC cannot confirm that if there was 100% IPP development the net revenue requirement impact for Alternative 3 would be less than for Alternatives 1 and 2.

Further, please see BCTC’s response to BCUC IR 1.22.3. As noted, there is significant uncertainty in the probability of IPP development and substantial investment is required, to realize any of the potential benefits to ratepayers.

As noted in BCTC’s responses to BCUC IR 1.23.1 and BCUC IR 1.26.1, a technical impact analysis was not undertaken to define energy transfer limits that may apply to the integration of future IPP development. Therefore, Alternative 3 as represented in the analysis shown in BCTC’s response to BCUC IR 1.26.1, has not been assessed in a way which allows BCTC to estimate the cost that would be incurred to interconnect 100% of the generation potential. It is difficult to reliably estimate such cost until IPP projects are further advanced. The analysis was useful to illustrate the range of potential economic benefits, taking into consideration a range of scenarios for IPP development.

Any benefit scenario must be weighed against significant hurdles associated with Alternative 3 to build and maintain required facilities over adverse terrain, especially between the identified resource clusters. As noted in Exhibit B-1 at page 52, BCTC concluded that future integration of IPP development potential could be achieved through other more economical alternatives.
2.103.0  Reference:   Exhibit B-3, BCUC 1.25.1, 1.26.1, 1.68.1
                   Net Economic Effect and Revenue Impact Analysis

2.103.2  Does the net revenue requirement shown in the referenced responses include the effects of transmission losses? If not, why not?

RESPONSE:

The net revenue requirement shown in the referenced responses includes the effects of energy losses.
2.103.0 Reference: Exhibit B-3, BCUC 1.25.1, 1.26.1, 1.68.1
Net Economic Effect and Revenue Impact Analysis

2.103.3 Please provide the figures shown in the responses to BCUC 1.25.1 and 1.26.1 with the range of benefits shown in the response to BCUC 1.68.1. Is it appropriate to compare the information in the referenced responses, and if so, please reconcile any differences in that information?

RESPONSE:

The responses to the three referenced IRs reflect the same benefits with the only difference being the discount period. The benefits shown in BCTC’s responses to BCUC IR 1.25.1 and 1.26.1 have been discounted to F2010$ whereas the benefits shown in BCUC IR 1.68.1 have been discounted to F2009$.

It is not appropriate to compare the information in the referenced responses as the costs reflected in BCTC’s response to BCUC IR 1.68.1 is a PV comparison of the capital cost for the alternatives (i.e. direct capital cost, capital overhead, ongoing OMA and grants and taxes) and does not reflect the PV of the revenue requirement impact of the alternatives as shown in BCUC IRs 1.25.1 and 1.26.1.

Please refer to Exhibit B-1, Figures 4.1 and 4.2 for benefits shown in the same range as BCUC IR 1.68.1.
2.104.1 Reference: Exhibit B-3, BCUC 1.30.5
Overview of 230 kV Transmission Route Corridor Options

Please provide a comparison of the number of private land parcels and the distance over each crossed by each of the options discussed in the referenced response.

RESPONSE:

The proposed diversion route (Option 4) does not cross any private land parcels. Other alternatives required crossing of private parcels ranging from 800 m to 1800 m as set out below:

Option 1: 2 private parcels (50 m and 750 m) 800 m combined

Option 2: 2 private parcels (800 m and 1150 m) 1950 m combined

Option 3: 2 private parcels (800 m and 1000 m) 1800 m combined

Option 4: 0 private parcels
2.104.0 Reference: Exhibit B-3, BCUC 1.30.5
Overview of 230 kV Transmission Route Corridor Options

2.104.2 Please provide an estimate of the increased cost for “side hill” construction associated with Options 2 and 3, as compared to the overall costs for Options 1 and 4.

RESPONSE:

Please see the Toby Creek Diversion Supplement for the CPCN Application - Toby Creek Diversion submitted filed on 20 April 2010 (Exhibit B-6). Cost between the options varied less than $10,000 for “side hill” construction and was not material to the selection of Option 4 as BCTC’s proposed route.
2.105.0 Reference: Exhibit B-3-1, BCUC 1.33.1
Private Land

2.105.1 Please explain why BCTC describes the difference between the private property requirements as “significantly less” for Corridor B as compared to Corridor A, especially since Corridor A appears to impact fewer private properties.

RESPONSE:
The statement refers to the difference in the length of right-of-way on private property that would still have to be acquired. As noted in Exhibit B-1, BC Hydro had acquired some rights-of-way in the area. Corridor A would require the acquisition of an extra 4 km of right-of-way as compared to Corridor B.
2.106.0 Reference: Exhibit B-3, BCUC 1.36.2
Kicking Horse Substation

2.106.1 Please provide an estimate of the incremental cost for adding a 15 MVA 25 kV tertiary winding to each proposed KHS transformer, along with the incremental cost of adding distribution regulators, and compare this against the cost of a separate 15 MVA 69/25kV transformer.

RESPONSE:

The installed cost for adding a three phase 15 MVA 25 kV tertiary winding to each proposed KHS transformer, and providing distribution (voltage) regulators and circuit breakers is $1.3M per transformer, including contingency. Overhead, IDC and inflation are excluded.

The installed cost for one three phase 15 MVA 69/25 kV transformer, complete with circuit breaker and disconnect switches, is $2.9M including contingency. Overhead, IDC and inflation are excluded.

The accuracy range of these estimates is -50% to +100%.
2.106.0 Reference: Exhibit B-3, BCUC 1.36.2
Kicking Horse Substation

2.106.2 Please explain how a feeder fault combined with a breaker failure could possibly take the proposed INV-KHS 230 kV transmission line out of service.

RESPONSE:

The possibility of a feeder fault with feeder breaker failure forcing the proposed INV-KHS transmission line out of service would depend on the implemented design of the substation. The scenario would arise, for example, if the KHS transformers were to be installed without any high side breakers. With this configuration a feeder fault combined with a circuit breaker failure would result in the loss of both transformers and the 230 kV transmission line.
2.107.0 Reference: Exhibit B-3, BCUC 1.36.3

2.107.1 The response does not consider that the Application proposes the retention of the existing GDN 69/25 kV transformers and new 69 kV ring bus facilities (see BHC response 1.37.1 and 1.56.1) for an outage to the 230 kV line to back-feed GDN from 60L271, hence the N-1 contingency criteria is met- except under max load conditions where load shed may be required. Please confirm that the answer to the original question is essentially ‘Only 1 transformer is required at this time except under peak load conditions wherein the N-1 criterion is not met’.

RESPONSE:

BCTC’s response to BCUC IR 1.36.3 does consider that Exhibit B-1 proposes the retention of the existing GDN 69/25 kV transformers and new 69 kV ring bus facilities. Two KHS 230/69 kV transformers are required at this time to meet BCTC’s system planning criterion during peak-load conditions.

The statement “Only 1 transformer is required at this time except under peak load conditions wherein the N-1 criterion is not met” does not accurately reflect BCTC’s response to BCUC IR 1.36.3 and the N-1 planning criterion.

Assuming a single transformer at KHS, loss of the transformer, would result in prolonged outages even considering some available back-up from 60L271. Such outages may continue until the replacement of the transformer. These outages are not dependent on system peak conditions for which the system is designed, but on the available supply limitation of 60L271.
2.108.0 Reference: Exhibit B-3, BCUC 1.36.9

2.108.1 The most cost effective time to acquire sufficient property for future expansion is concurrent with the original purchase (GDN sub for example). Please confirm that the property to be purchased will accommodate all foreseeable IPP transformation requirements.

RESPONSE:

BCTC is of the view that the property to be acquired for the proposed KHS will accommodate foreseeable IPP transformation requirements.
2.109.0 Reference: Exhibit B-3, BCUC 1.39.1 and 1.69.2
Financial Assumptions and Calculations

2.109.1 Some of the cells in the excel model that BCTC provided in response to BCUC 1.69.2, appear to contain hardcoded values rather than formula calculated values for both IDC and capital overhead. Please provide the formula calculation for IDC, showing the rate of 6.55%, which reconciles to Line 14 in the table below. Please provide the formula calculation for capital overhead, showing the rate of 3% for F2010, which reconciles to Line 13 in the table below.

<table>
<thead>
<tr>
<th>Line No. in millions</th>
<th>Initial Estimate</th>
<th>Total</th>
<th>F2010</th>
<th>F2011</th>
<th>F2012</th>
<th>F2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Cost</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phases</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 PMO</td>
<td>0.3</td>
<td>0.2</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2 Regulatory</td>
<td>0.3</td>
<td>0.2</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>3 Environmental</td>
<td>0.7</td>
<td>0.6</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Services</td>
<td>0.3</td>
<td>0.2</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4 Property</td>
<td>1.3</td>
<td>1.1</td>
<td>0.2</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>5 Engineering</td>
<td>1.6</td>
<td>0.8</td>
<td>0.8</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Services</td>
<td>0.1</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>6 System Planning</td>
<td>0.1</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>7 Public Consultation</td>
<td>0.1</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>8 Subtotal - Definition Phase</td>
<td>4.7</td>
<td>3.3</td>
<td>1.4</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>10 Overhead</td>
<td>0.1</td>
<td>0.1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>11 Contingency</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 Project Total - Definition Phase</td>
<td>3.0</td>
<td>5.7</td>
<td>3.5</td>
<td>1.7</td>
<td>0.3</td>
<td>0.2</td>
</tr>
</tbody>
</table>

RESPONSE:

The attached spreadsheet “BCUC 2.109.1.xls” provides the calculation of the capital overhead and IDC reflected in lines 13 and 14 above.
2.109.0  Reference:  Exhibit B-3, BCUC 1.39.1 and 1.69.2
Financial Assumptions and Calculations

2.109.2  What is the average life of BCTC’s Transmission facilities?

RESPONSE:

Composite depreciation rates are used in BCTC’s financial calculations to reflect the forecast average life of facilities.

The depreciation rates used to calculate the forecasted depreciation for the CVT Project and the alternatives are based on composite rates for the existing Transmission assets, 1.9% lines and 3.1% for stations. The average depreciation rate for the preferred CVT alternative is 2.3%.
2.109.0 Reference: Exhibit B-3, BCUC 1.39.1 and 1.69.2
Financial Assumptions and Calculations

2.109.3 Please explain why the annual Grants and Taxes amounts are not inflation adjusted?

RESPONSE:

With the exception of the capital cost additions none of the revenue requirement cost elements have been inflated and all are shown in F2010$. The present value impact of the revenue requirement has been discounted to F2010 using the real discount rate.
2.109.0 Reference: Exhibit B-3, BCUC 1.39.1 and 1.69.2
Financial Assumptions and Calculations

2.109.4 Provide the details of the initial estimate in column (a).

RESPONSE:

Please see BCTC’s response to BCUC IR 2.79.4.
2.109.0 Reference: Exhibit B-3, BCUC 1.39.1 and 1.69.2
Financial Assumptions and Calculations

2.109.5 Why is the cost forecast $5.7 million and not $5.5 million- doesn’t IDC stop once the project is placed in service in October 2012?

RESPONSE:

Yes, IDC stops in F2013 (October 2012), please refer to the attached spreadsheet “BCUC 2.109.1.xls” for the calculation. The total forecasted Definition Phase cost is $5.7 million.
2.109.0 Reference: Exhibit B-3, BCUC 1.39.1 and 1.69.2
Financial Assumptions and Calculations

2.109.6 Please explain why the subtotal definition phase cost is $4.5 million in some responses and $4.7 million in this response?

RESPONSE:

The difference in the subtotalled definition phase costs is due to rounding.
2.110.0 Reference: Exhibit B-3, BCUC 1.40.1
Revenue Requirement Impact - Losses

2.110.1 The referenced response appears to suggest that by F2014, the overall losses for the project, despite being lower than the existing system, and will have “caught up” to present day levels of losses. Is this interpretation correct, and if not, why not? Please provide the supporting analysis to justify the $400,000 energy loss revenue requirement shown in Exhibit B-1, Table 5-6.

RESPONSE:

The interpretation is not correct. The 2009/10 system loss is 6.5 MW based on a Golden area load of 28.4 MVA and the system loses with the Columbia Valley Transmission Project in service as proposed will reach that level in 2031/32 when the Golden area load reaches approximately 55 MVA.

Please refer to Exhibit B-1 Appendix B, Table D, page 66 for the supporting analysis to support the $400,000 energy loss revenue requirement shown in Exhibit B-1, Table 5-6, page 83. The energy loss was determined to be $360k which was subsequently rounded off to $0.4 million as shown in Table 5-6. The calculation of the $360k was based on:

- Alternative 2 Peak load losses of 2.62 MW
- A Load Loss Factor of 21.5% at Golden Substation
- BC Hydro Benchmark Energy Value of $74/MWh

The calculation for the cost of annual Energy Losses

\[ = 2.62 \times 21.5\% \times 8760 \text{ hrs} \times 74 = $365k^* \]

*(note the difference to $360k is due to rounding off the value of the energy loss).
2.111.0 Reference: Exhibit B-3, BCUC 1.45.1

2.111.1 Please explain why these costs are born by ratepayers and not the Crown or B.C Hydro's shareholder?

RESPONSE:

This question was referred to BC Hydro for response. The following is BC Hydro’s response:

BC Hydro is of the view that First Nation consultation and accommodation costs, and the cost of sharing project benefits with First Nations, are properly Project costs that BC Hydro is entitled to recover in rates for the following four main reasons.

First, ratepayers benefit when BC Hydro consults with First Nations, and enters into benefit agreements where appropriate, because certain important project risks are reduced, if not eliminated entirely. For example, if a First Nation challenges, in court, the validity of a permit, authorization or tenure, a project may be delayed by many months if not years, which invariably increases project costs and delays the benefits of the project to ratepayers (eg. enhanced reliability). Benefit Agreements and a support letter must include an acknowledgment by First Nations that they have been adequately consulted and that they will not interfere with the construction or operation of the subject project.

Second, permitting agencies or tenure-granting agencies (such as the Integrated Land Management Bureau) often require BC Hydro or BCTC to provide a First Nations consultation record as part of the application for the permit or land tenure. As these permits and tenures are required for the Project to proceed, it is appropriate for the costs of such consultations and, if appropriate, accommodation in support of those permits and tenures to be recovered in rates.

Similarly, the BCUC, in the recently published First Nation Guidelines, encourages Crown agencies like BC Hydro and BCTC to provide the BCUC with sufficient consultation evidence so the Commission can assess whether or not consultation and accommodation was reasonable and adequate to the stage of the BCUC’s decision.

Finally, in the *Kwikwetlem First Nation* case (ILM), the BC Court of Appeal stated that BC Hydro had a duty to consult with First Nations which arose when BCTC became aware that the means it was considering to maintain adequate supply of power to consumers in the lower mainland had the potential to affect Aboriginal rights and title. The facts in ILM are quite similar to the CVT Project in that BCTC is applying to the BCUC for a CPCN for a transmission project. Based on the *Kwikwetlem First Nation* decision, a duty to consult with First Nations arose when BC Hydro
and BCTC became aware that the CVT Project may affect the rights and interest of the identified First Nations.

It is entirely appropriate for BC Hydro to recover the costs of consulting and accommodating First Nations, including benefits agreement costs, if the costs are incurred to reduce project risk, satisfy permitting and tenure-granting agencies, provide evidence of adequate consultation to the BCUC, and to satisfy consultation obligations in accordance with the BC Court of Appeal *Kwikwetlem* decision.
2.112.0 Reference: Exhibit B-3, BCUC 1.48.1

2.112.1 Please describe what is contemplated under capacity building and training opportunities?

RESPONSE:

This question was forwarded to BC Hydro for response. The following is BC Hydro’s response:

In general, capacity building and training opportunities depend on the interests expressed by the First Nations and opportunities to enhance First Nations participations in contract work. In addition, First Nations, at their request, may participate in studies that help to inform the project and at the same time enhance First Nations documentation of critical information about their asserted traditional territories.
2.113.0 Reference: Risk Level
Exhibit B-3, BCUC 1.53.1 and Attachment to 1.53.1

From Attachment to 1.53.1:

<table>
<thead>
<tr>
<th>IMPACT CRITERIA</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relationships</td>
<td>External opposition resulting in short term delays or minor modifications to work plans</td>
<td>External opposition affecting BCTC’s ability to implement its work plans is constrained and/or substantive modifications of its work plans are required.</td>
<td>External opposition resulting in increased regulatory oversight; shareholder scrutiny and/or restricted access to work sites.</td>
<td>External opposition resulting in increased regulatory/legislative/court action or government intervention resulting in a loss of BCTC’s major project sites including restricted access to corporate mandate, responsibilities impacting</td>
<td>External opposition resulting in loss of license to operate and/or imposed corporate restructuring</td>
</tr>
</tbody>
</table>

2.113.1 What were the key identification factors in this project that have lead BCTC to conclude that a Level 3 rating was appropriate for the “Relationship” Impact Criteria. In other words, what were the key elements in the 2 risk factors (public opposition and First Nations consultations) that were subject to:

- Increasing regulatory oversight,
- Shareholder scrutiny, and/or
- Restricted access to work sites

RESPONSE:

A rating of three was given to both public and First Nations relationships because in May 2009, at the time that the risk rating was conducted, there was some uncertainty as to increasing regulatory oversight given the recent BC Court of Appeal decision pertaining to the BCUC regulatory process. In addition, there had been statements made during early public consultation about resistance to the leading alternative presented by BCTC. There were no key elements in the risk ratings that were specifically related to shareholder scrutiny.
2.114.0 Reference: Risk Management
Exhibit B-3, BCUC 1.53.4 and 1.53.5

“BCTC believes that the risks identified will not impact the financial assessment of the Project beyond amounts currently allocated for project contingency.” (BCUC 1.53.4)

2.114.1 Does the above statement from BCUC 1.53.4 still hold true after factoring in all potential First Nations accommodation costs?

RESPONSE:

Yes. While there remains some uncertainty to quantifying all potential First Nations accommodation costs, BCTC continues to believe that remaining uncertainty will not impact the financial assessment of the Project.
2.114.0 Reference: Risk Management
Exhibit B-3, BCUC 1.53.4 and 1.53.5

“Mitigation measures were identified to minimize risk.” (BCUC 1.53.5)

2.114.2 What are the estimated costs of the risk mitigation activities identified on page 180 of the Application? (please include any required overtime due to an accelerated construction schedule and processing fees by the Integrated Land Management Bureau).

RESPONSE:

With the implementation of mitigation measures defined in Exhibit B-1, Section 9; the probability of occurrence of these risk events is now low.

The processing time required by Integrated Land Management Bureau to adjudicate an application is 120 days. This time period can extend up to another 120 days or more depending on the work load and available resources in the regional area. BCTC can not expedite this process. Without the Crown Land Licence of Occupation from ILMB, BCTC can not start the construction process. If for some reason, the ILMB adjudication is delayed, the in-service date of the project will be impacted. To mitigate this risk, BCTC has submitted an application to the ILMB. The processing (application) fees charged by ILMB are:

- 230 kV right of way application: $1050
- 69 kV right of way application: $1050
- KHS Substation application: $1050
- KHS Access Road application: $525

BCTC’s current project schedule is aggressive and opportunity for further acceleration is limited. Additional costs, if any, would depend on a specific delay scenario.

Please see BCTC’s response to BCUC IR 1.53.6 regarding cost impact due to delay.
2.114.0 Reference:  Risk Management  
Exhibit B-3, BCUC 1.53.4 and 1.53.5

“Mitigation measures were identified to minimize risk.” (BCUC 1.53.5)

2.114.3 Were these risk mitigation costs included in BCTC’s financial assessments? Please explain.

RESPONSE:

BCTC’s financial assessment included a Monte Carlo analysis to quantify an appropriate contingency amount.

Some mitigation measures have been implemented through the definition phase to minimize risk. BCTC believes that remaining measures, if necessary, can be accommodated through project contingency.
2.115.0 Reference: Risk Management
Exhibit B-3, BCUC 1.53.6

“The cost of the project would be increased by $1 million with a 6 month delay and would be increased by $2 million with a 12 month delay, due to interest during construction.” (BCUC 1.53.6)

“The impacts of these risks are subject to potential measures available to meet interim growth demand as outlined in the Application (Exhibit B-1) at Section 3.6, pages 32-33.” (BCUC 1.53.6)

On page 32-33 of the Application, BCTC discusses the options available to meet load growth in the interim period. These options may include industrial load curtailment, increased supply from a small distribution IPP, battery bank storage facilities on the distribution system, and if necessary, temporary diesel generation.

2.115.1 Does the excerpt on page 32-33 of the application suggest that there could be incremental costs, aside from just interest during construction alone, if there were project delays for any reason?

RESPONSE:

There will be additional incremental costs to meet the potential load growth of 1.2 MVA during the winter 2012/13. The options listed on page 32-33 of Exhibit B-1 are general options and depending on the availability and specific load requirements, such interim measures may be implemented by BC Hydro Distribution.
2.115.0 Reference: Risk Management
Exhibit B-3, BCUC 1.53.6

“The cost of the project would be increased by $1 million with a 6 month delay and would be increased by $2 million with a 12 month delay, due to interest during construction.” (BCUC 1.53.6)

“The impacts of these risks are subject to potential measures available to meet interim growth demand as outlined in the Application (Exhibit B-1) at Section 3.6, pages 32-33.” (BCUC 1.53.6)

On page 32-33 of the Application, BCTC discusses the options available to meet load growth in the interim period. These options may include industrial load curtailment, increased supply from a small distribution IPP, battery bank storage facilities on the distribution system, and if necessary, temporary diesel generation.

2.115.2 Has BCTC conducted a forecast of the costs for each of the interim load growth solutions identified on page 32-33 of the Application? If so, please provide the calculations and explain how these costs are to be funded.

RESPONSE:

BC Hydro has advised BCTC as follows:

BC Hydro notes that information on the battery bank storage option has been disclosed in its F2011 Revenue Requirements Application (Exhibit B-1, Appendix J, pages 79 and 80). Subject to approval by the Commission, BC Hydro will pay for the costs associated with this option with a portion of the costs proposed to be covered through the Clean Energy Fund.

With respect to an industrial load curtailment agreement, BC Hydro has also confirmed that discussions with an industrial customer are ongoing, however, a formal agreement has not yet been reached. Once an agreement has been reached, BC Hydro will pay for the costs associated with this option.

With respect to small distribution IPP, one IPP has applied to sell power to BC Hydro via the Standing Offer Program. The SOP application is proceeding through the process, however, an Energy Purchase Agreement (EPA) has not yet been signed. Interconnection costs will be allocated between the IPP and BC Hydro as outlined in the SOP Rules and standard Distribution interconnection policy while energy purchase costs are funded by BC Hydro.
With respect to temporary diesel generation, BC Hydro estimates the cost to be approximately $230,000 per year. This amount is expected to cover a 4 month temporary rental, installation, and operation during the annual winter peak period until the transmission line is in service. The costs will be paid by BC Hydro.
2.115.0 Reference: Risk Management
Exhibit B-3, BCUC 1.53.6

“The cost of the project would be increased by $1 million with a 6 month delay and would be increased by $2 million with a 12 month delay, due to interest during construction.” (BCUC 1.53.6)

“The impacts of these risks are subject to potential measures available to meet interim growth demand as outlined in the Application (Exhibit B-1) at Section 3.6, pages 32-33.” (BCUC 1.53.6)

On page 32-33 of the Application, BCTC discusses the options available to meet load growth in the interim period. These options may include industrial load curtailment, increased supply from a small distribution IPP, battery bank storage facilities on the distribution system, and if necessary, temporary diesel generation.

2.115.3 What is the worst case scenario impact to the forecast project cost, should this project experience a substantial delay?

RESPONSE:

The possible interim measures identified in Exhibit B-1 are short term measures and not appropriate for substantial delay in the project.

The worst case scenario is a multi-year delay which would result in increased project costs due to continuing IDC or definition phase cost write-offs. Project costs also likely rise with inflation.

Customer impacts associated with substantial multi-year delay may be significant if load curtailment must be implemented.
2.116.0 Reference: Exhibit B-3, BCUC 1.54.3 (see also 1.14.9)

2.116.1 Please provide an analysis if the 230 kV or 138 kV transformation low side voltage was 69 kV (i.e. 60L271 remains at 60 kV) and cover the same points as the IR1 response. How will this option impact BC Hydro’s SDA plans? Please provide an estimate of the cost savings of this option compared to BCTC’s preferred option.

**RESPONSE:**

For an analysis of the configuration in which a 230/69 kV or 138/69 kV source station is constructed in the SPN/PSN area with 60L271 remaining at 69 kV, please refer to BCTC’s response to BCUC IR 2.95.1. This configuration would not meet the long term supply requirements for the upper Columbia Valley and was not considered. It would only meet load supply requirements at GDN up to 2020/21.

This configuration would have no impact on BC Hydro’s SDA plan because the existing 69 kV system would be retained and BC Hydro’s present SDA plan in this area (i.e., GDN 12/25 kV voltage conversion, GDN 69/25 kV transformation upgrade, RDM 12 kV voltage regulator replacement and ATH 69/25 kV transformer replacements) would still need to be implemented.

There would be no SDA cost savings in comparison to the CVT Project because the existing 69 kV system is retained under both.

The suggested 138 kV and 230 kV injection configurations are estimated at $112 m and $106 m respectively. (Estimates include contingency, overhead, IDC and inflation and have an accuracy of -50/+100%).
2.117.0 Reference: Exhibit B-3, BCUC 1.58.1
System Losses

2.117.1 Considering the small reduction in losses to be realized from closed loop operation of 60L271 as shown in the referenced response, how much cost could be saved by eliminating the 69 kV ring bus configuration at GDN?

RESPONSE:

The cost of GDN could be reduced by approximately $5M, excluding overhead, IDC and inflation, by eliminating the 69 kV ring bus configuration. Accuracy of this estimate is -50% to +100%.

It should be noted that, with this configuration, customer outages would be required to transfer the load between 60L272 and 60L271.
2.118.0 Reference: Exhibit B-3, BCUC 1.59.1, 1.59.2
Reliability Assessment of 60L223

2.118.1 Please explain the reason for the 205.82 hour outage on 60L223 in F2009, and why the repair took a relatively long time.

RESPONSE:

This long duration outage event occurred in the winter on 7 January 2009. It was reported as a pole top fire caused by defective equipment. Because the event occurred during a winter period, the repair and the long restoration time was likely due to the inclement weather condition and the location with limited the access due to adverse and remote terrain.
2.118.0 Reference: Exhibit B-3, BCUC 1.59.1, 1.59.2
Reliability Assessment of 60L223

2.118.2 For reliability analysis purposes, would the 2009 outage of 60L223 constitute an outlier in the 2.5 beta method?

RESPONSE:

In order to respond to this IR, it is very important to clarify how the “2.5 Beta Method” is applied to reliability assessment.

In reliability assessments, there are two basic types of reliability indices. The first type is designated as predictive indices [1] and the other type is designated as performance indices [2, 3]. Predictive indices provide information relevant for use for future system reliability and are normally associated with system planning. Past performance indices reflect the historical system reliability and are therefore related to the actual operation performance of the system.

In the performance index assessment of electric distribution systems, the “2.5 Beta Method” has been introduced in the IEEE Guide for Electric Power Distribution System Reliability Indices (IEEE Standard 1366) [4] to identify major outage events and to remove these major outages from the annual performance outage statistics. Although several utilities and regulators have adopted this method, the application of the “2.5 Beta Method” is limited to electric power distribution systems only and the method has not been adopted or applied to transmission reliability performance measures in the Canadian Electricity Association (CEA), Electric Power System Reliability Assessment protocols [5, 6]. The “2.5 Beta Method” also has some shortcomings because it does not consider the actual system design criteria and there is no physical reason why the reliability index is automatically assumed to be log-normally distributed in the “2.5 Beta Method” [7]. Reference 7 has presented a strong criticism against the “2.5 Beta Method”. In BCTC’s view, caution should be taken to extend this method to transmission system planning.

As noted above, the “2.5 Beta Method” is solely applied to reliability performance indices (as a reflection of the actual operation performance of the system) for benchmarking against the specified goal/target reliability performance. The “2.5 Beta Method” is not designed or intended for the reliability analysis used in obtaining the predictive indices for system planning purposes. The reason is that uncertainty factors (such as different causes of outages resulting in a wide range of outage durations) should be included when conducting probabilistic reliability assessment to obtain predictive indices. Applying the “2.5 Beta Method” to exclude some outages that actually occurred in the past is a manipulation of uncertainties to some extent and the predictive reliability results will move towards deterministic values involving with less
uncertainty. In other words, the predictive results based on reliability analysis will move away from probabilistic nature involving with high uncertainty.

In BCTC’s view, the “2.5 Beta Method” is not applicable to circuit 60L223, which is part of transmission system (not a distribution system), based on the CEA Electric Power System Reliability Assessment protocols [5, 6]. Therefore, the 2009 outage of circuit 60L223 should not be excluded from the outage considerations. From the predictive index standpoint, the predictive indices presented in the CVI CPCN Application were obtained based on the probabilistic reliability analysis for system planning purposes. The use of the “2.5 Beta Method” to exclude some outage events would bias the probabilistic reliability evaluation towards a more predictive indices and would be inappropriate in this case because the long outage duration due to the actual 2009 outage is not beyond expectation. That is, outages caused by defective equipment do occur during the winter periods and limited access due to the rugged mountain terrain and extreme weather conditions could be encountered.

References:


2.118.0 Reference: Exhibit B-3, BCUC 1.59.1, 1.59.2
Reliability Assessment of 60L223

2.118.3 Please provide the reliability comparison shown in the response to BCUC 1.59.1 using only the most recent 10 years of reliability data for 60L223, for both cases including and excluding the F2009 outage, and apply the resulting reliability scaling factors to the Alternative 3 analysis provided in the Application.

RESPONSE:

The reliability of circuit 60L223 based on the most recent 10-year (F2000-F2009) outage statistics including and excluding the 2009 outage as well as the average 60 kV circuit reliability are shown in Table 1. The probabilistic reliability results for Alternative 3 using the information in Table 1 are presented in Table 2 for both including and excluding the F2009 outage cases.

Table 1: Reliability of circuit 60L223 based on 10-year (F2000-F2009) outage statistics including and excluding the 2009 outage compared against the 10-year (F2000-F2009) average 60 kV circuit reliability in South Interior (line-related forced outages only)

<table>
<thead>
<tr>
<th>Component</th>
<th>Failure Frequency (failure/year/65km)</th>
<th>Repair Time (hours/failure)</th>
<th>Unavailability (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 60L223 Including the 2009 Outage</td>
<td>3.6000</td>
<td>15.54</td>
<td>0.6388</td>
</tr>
<tr>
<td>2 60L223 Excluding the 2009 Outage</td>
<td>3.5000</td>
<td>10.11</td>
<td>0.4038</td>
</tr>
<tr>
<td>3 Average 60 kV circuit</td>
<td>0.4918</td>
<td>11.32</td>
<td>0.0636</td>
</tr>
</tbody>
</table>

The reliability of circuit 60L223 presented in Table 1 was summarized from the response to BCUC IR 1.59.2. The reliability factor based on the comparison of the circuit 60L223 against the average 60 kV circuit using the most recent 10 year outage statistics is re-calculated and then applied to the reliability analysis results presented in Table 2.
Table 2: Comparison of the reliability results for Alternative 3 based on the 10-year (F2000-F2009) statistics including and excluding the 2009 outage

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Unavailability (hours/year)</th>
<th>Cumulative EENS (MWh/30 years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Alternative 3: using 10-year statistics</td>
<td>51.72</td>
<td>3918.50</td>
</tr>
<tr>
<td>including the 2009 outage</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 Alternative 3: using 10-year statistics</td>
<td>33.42</td>
<td>2890.42</td>
</tr>
<tr>
<td>excluding the 2009 outage</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 2 indicates that the reliability results based on 10-year statistics including the 2009 outage is still quite close to the results based on using 20-year statistics presented in Exhibit B-1. This is because the reliability factors representing a rugged terrain with extreme weather condition calculated based on 10-year and 20-year statistics are similar. On the other hand, when the 2009 outage is excluded the reliability results based on using 10-year statistics is improved. However, it is important to note that the predictive reliability results for Alternative 3 based on an exclusion of the 2009 outage should be considered with caution as described in BCTC’s response to BCUC IR 2.118.2.

The reliability result for Alternative 3 based on an exclusion of the 2009 outage is still significantly worse than those of Alternatives 1 and 2 as presented in Exhibit B-1.
2.119.0 Reference: Exhibit B-3, BCUC 1.61.1
Load Forecast

2.119.1 Please explain the reason for the load increase at INV in 2019 and 2020 shown in the referenced response.

RESPONSE:

This response has been filed confidentially under separate cover.
2.120.0 Reference: Exhibit B-3, BCUC 1.64.1, 1.64.3 Pumped Storage Assessment

2.120.1 Please provide an assessment of the annual “delivery” vs. “re-charge” cycles of a 15 MW pumped storage facility until F2025 for two cases, the first case being with only 60L271 in service, and the second case with 60L271 converted to 138 kV operation and being supplied from INV. Please demonstrate whether 60L271 is insufficient to accommodate the “re-charge” cycle in the near term.

**RESPONSE:**

The “recharge” cycle of a 15 MW pumped-storage facility typically occurs during the light-load period (approximately 6 to 7 hours) when the capacity is available in the system to supply the motors that pump the water from a lower-level basin to a higher-level reservoir, essentially refilling the pumped-storage facility in the process. The “delivery” cycle typically is shorter than the “recharge” cycle and occurs during the peak-load period when the system doesn’t have sufficient capacity to meet the system load demand and the deficiency is met by power generated by the pumped-storage facility.

With only 60L271 in service, assuming the 15 MW pumping station is located at Susan Lake approximately 55 km from GDN and is interconnected to GDN via a 69 kV transmission line, the combined pumped-storage and 60L271 supply system will only be capable of supplying the GDN area peak-load demand until F2018. This is based on the limited supply capacity available in the 69 kV system for pumping purposes under light-load conditions. Based on the capacity available, a maximum of approximately 9.2 MVA could be delivered to the pumping station in F2018. However, considering that 60L271 can only supply up to 29 MVA and assuming a typical 75% efficiency for a pumped-storage generating facility (i.e., a “delivery” of approximately 6.7 MVA based on a “recharge” load demand of approximately 9.2 MVA), then after considering the losses incurred in the transmission line between the pumped-storage facility and GDN (approximately 0.3MVA), the combined system could only supply up to a maximum of approximately 35.4MVA, marginally less than the GDN peak load of 35.5 MVA in F2018 (refer to the table below).
<table>
<thead>
<tr>
<th>Year</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>GDN load (MVA)</td>
</tr>
<tr>
<td>2</td>
<td>Additional power at GDN beyond 29MVA</td>
</tr>
<tr>
<td>3</td>
<td>Supplying Susan Lake capacity via 60L271 during light load period</td>
</tr>
<tr>
<td>4</td>
<td>Susan Lake Generation Capacity (75% efficiency)</td>
</tr>
<tr>
<td>5</td>
<td>Susan Lake deliverable capacity to GDN Considering line losses</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>F2013</strong></td>
</tr>
<tr>
<td>1</td>
<td>31.9</td>
</tr>
<tr>
<td>2</td>
<td>2.9</td>
</tr>
<tr>
<td>3</td>
<td>12.0</td>
</tr>
<tr>
<td>4</td>
<td>9.0</td>
</tr>
<tr>
<td>5</td>
<td>8.7</td>
</tr>
</tbody>
</table>

With 60L271 converted to 138 kV operation and being supplied from INV, the 138 kV line would have sufficient capacity to supply both the GDN area load and the pumped-storage load under light-load conditions until about 2025/2026.
2.121.0 Reference: Exhibit B-3, BCUC 1.65.4
Biomass Opportunities

2.121.1 The referenced response does not address why the option identified in the original Information Request does not warrant further investigation. Please discuss whether the option can present an economically viable opportunity to defer the need for the proposed CVT project.

RESPONSE:

The option does not present an economical viable opportunity to defer the need for the CVT Project. Please see BCTC’s response to BCUC IR 1.65.2 which was filed confidentially.
2.121.0 Reference: Exhibit B-3, BCUC 1.65.4
Biomass Opportunities

2.121.2 Please discuss BCTC’s obligations to the ratepayers of British Columbia and the public interest to actively pursue economically viable non-wires projects that could defer transmission projects, rather than rely on non-wires project proponents to present projects to BCTC.

RESPONSE:

BCTC’s obligations under its Open Access Transmission Tariff are to be responsive to customer requests. While BCTC has considered potentially economically viable non-wires solutions, a process of identifying and assessing potential non-wires solutions in the transmission planning process is now incorporated into BCTC’s Open Access Transmission Tariff, as set out in Attachment K. BCTC has met any obligation it has to assess non-wires projects through the following:

Over a period of years it has provided information to stakeholders, including potential non-wires project proponent published information about its plans for development of the transmission system in the Columbia Valley.

Through these transparent processes, BCTC sought information from stakeholders.

BCTC retained an independent consultant, KWL, to conduct an assessment of IPP potential in the region.

In identifying and assessing the alternatives available to meet the needs in the upper Columbia, Valley BCTC took into account the information gathered in those processes along with load and generation forecasts provided by BC Hydro. BCTC also took into account its obligation to provide safe, reliable, sufficient transmission and identified the CVT Project as the preferred alternative.
2.122.0  Reference:  Interest During Construction
Exhibit B-3, BCUC 1.71.1 and 1.71.2

“BC Hydro provided the 6.55% IDC rate, which reflects BC Hydro’s weighted average cost of debt for F2010.” (BCUC 1.71.2)

2.122.1  According to BC Hydro’s F2011 Revenue Requirement Application, 6.55% is the weighted average cost of debt for F2009 while the F2010 weighted average cost of debt is 3.95%. (Appendix A, Financial Schedule 8.0, p.37, Line 60, F2011 BC Hydro Revenue Requirement Application). Should BCTC be using 3.95% instead of 6.55% as the IDC rate?

RESPONSE:

As noted in BCTC’s response to BCUC IR 1.71.1 the relevant IDC rate at the time of the estimate was 6.55%.

The actual F2010 weighted average cost of debt shown in BC Hydro’s F2011 Revenue Requirement Application will not be available until mid-May 2010. The 3.95% provided in BC Hydro’s F2011 Revenue Requirement Application for F2010 is a forecast. BCTC will apply BC Hydro’s F2010 actual cost of debt as its Interest During Construction (IDC) rate for its actual capital expenditures in F2011.
2.122.0 Reference:  Interest During Construction
Exhibit B-3, BCUC 1.71.1 and 1.71.2

“BC Hydro provided the 6.55% IDC rate, which reflects BC Hydro’s weighted average
cost of debt for F2010.” (BCUC 1.71.2)

2.122.2 What is the impact to the PV of Total Revenue Requirement for
Alternative #2 if the rate of 3.95% were used as the IDC rate?

RESPONSE:

The table below provides the PV of the Total Revenue Requirement impact for Alternative 2
using 6.55% IDC and 3.95% IDC.

<table>
<thead>
<tr>
<th>Preferred Alternative</th>
<th>6.55% IDC</th>
<th>3.95% IDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>($ millions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 Project Cost</td>
<td>154.1</td>
<td>148.7</td>
</tr>
<tr>
<td>Present Value Project Cost</td>
<td>131.3</td>
<td>126.6</td>
</tr>
<tr>
<td>Present Value Revenue Requirement</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Return on Equity</td>
<td>51.9</td>
<td>50.1</td>
</tr>
<tr>
<td>Finance Charges</td>
<td>79.8</td>
<td>79.4</td>
</tr>
<tr>
<td>Depreciation</td>
<td>43.7</td>
<td>42.2</td>
</tr>
<tr>
<td>OM&amp;A</td>
<td>3.8</td>
<td>3.8</td>
</tr>
<tr>
<td>Grants &amp; Taxes</td>
<td>7.6</td>
<td>7.6</td>
</tr>
<tr>
<td>7 Subtotal</td>
<td>186.8</td>
<td>183.1</td>
</tr>
<tr>
<td>Energy Loss</td>
<td>7.0</td>
<td>7.0</td>
</tr>
<tr>
<td>9 Total Revenue Requirement</td>
<td>193.8</td>
<td>190.1</td>
</tr>
<tr>
<td>F2010 TRR</td>
<td>9,368.8</td>
<td>9,364.8</td>
</tr>
<tr>
<td>% Impact</td>
<td>1.99%</td>
<td>1.96%</td>
</tr>
<tr>
<td>F2010 BC Hydro Revenue Requirement</td>
<td></td>
<td></td>
</tr>
<tr>
<td>% Impact</td>
<td>0.41%</td>
<td>0.40%</td>
</tr>
</tbody>
</table>
2.123.0 Reference: Exhibit B-3, BCUC 1.71.3
MMK Consulting Report

2.123.1 In the referenced response, BCTC states that inflation has been virtually flat from May 2009. Please provide a comparison of the both the general inflation rate and the construction inflation rate forecast by MMK Consulting from the May 2009 report, and from the two previous MMK Consulting reports. If BCTC does not have the previous two MMK Consulting reports, please request these from BC Hydro.

RESPONSE:

The table below compares the BC CPI and the Non-Residential Construction Index (seven cities) to the forecast made by MMK for April 2008, September 2008, and May 2009.

<table>
<thead>
<tr>
<th>Period</th>
<th>BC CPI Annual Increase (%)</th>
<th>Non-Residential Construction Annual Increase (%)</th>
<th>MMK April 2008 Forecast</th>
<th>MMK Sept 2008 Forecast</th>
<th>MMK May 2009 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 April 2008 – September 2008</td>
<td>4.1%</td>
<td>17.0%</td>
<td>4 to 6%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 September 2008 – May 2009</td>
<td>-2.1%</td>
<td>-13.9%</td>
<td>4 to 6%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3 May 2009 –</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2 to 4%</td>
</tr>
</tbody>
</table>
2.124.0 Reference: Capital Cost Estimate  
Exhibit B-3, BCUC 1.72.4

2.124.1 If the eventual actual cost for this project exceeds the approved CPCN value, how does BCTC propose to recover the cost overrun?

**RESPONSE:**

BCTC would seek to recover all project costs in rates. Please refer to BCTC’s response to BCUC IR 1A.1.6.1.
2.125.0 Reference: Exhibit B1, BCTC 3.32
Off-Load ATH from 60L271

2.125.1 Please discuss and provide a cost estimate for the option of adding a 230/69 kV transformer and switchgear at INV and adding another 69kV line (or thermally upgrading one or both of the existing 69kV lines if required and feasible) to ATH. Consider replacing the existing 60L271 or 60L270 structures to double circuit towers to accommodate a new 69kV line to ATH, add new 69kV line terminal (or ring bus) at ATH. Describe any additional equipment required to off-load ATH sufficiently to provide additional capacity for GDN to remove the voltage constraints? Please discuss the feasibility, timing and challenges and indicate the anticipated timeline before additional line capacity would be required to serve GDN (assuming no IPP injection at GDN). If there is an underbuilt restriction on 60L271/270 between INV and ATH, provide a cost estimate to underground this section(s) to remove the restriction. Include a construction sequence to limit customer outages to tie in the new facilities. The lack of line N-1 contingency to GDN and the need to upgrade transformer capacity in 2017/18 at GDN is duly noted for this option and need not be repeated in the response.

RESPONSE:

Off-loading ATH from the system as suggested would increase the GDN supply capability by approximately 1 MVA (increase to 30 MVA), hence the Columbia Valley Transmission Project would still be required by the winter of 2012/13. ATH is close to the voltage source at INV and does not contribute to the system voltage constraints at GDN.

The limited impact of this approach does not warrant further analysis.
2.125.0 Reference: Exhibit B1, BCTC 3.32
Off-Load ATH from 60L271

2.125.2 If the double circuit option is not feasible in 125.1 above, repeat 125.1 question with a new 69kV ROW to ATH in lieu of the D/C option (again, only if thermally upgrading 60L270/271 is not possible or sufficient).

RESPONSE:

An option based on a new right-of-way and transmission line from INV to ATH in lieu of a new double-circuit transmission line replacing one of the existing single-circuit transmission lines between INV and ATH would not meet the long term supply needs for the Upper Columbia Valley.

The limited impact of this approach does not warrant further analysis. Please refer to BCTC’s response to BCUC IR 2.125.1.
2.125.0 Reference: Exhibit B1, BCTC 3.32
Off-Load ATH from 60L271

2.125.3 Please provide a response if 125.1 and 125.2 options were extended to RDM.

RESPONSE:

Offloading ATH and RDM from the system as suggested would increase the GDN supply capability by approximately 3 MVA to 32 MVA. The Columbia Valley Transmission project would still be required by the winter of 2012/13. Please see BCTC’s response to BCUC IR 1.125.1.

The limited impact of this approach does not warrant further analysis.
2.125.0 Reference: Exhibit B1, BCTC 3.32
Off-Load ATH from 60L271

2.125.4 Can ATH be off-loaded from INV at distribution level?

RESPONSE:

ATH could be off-loaded from INV at the distribution level but it would require the construction of approximately 6 express feeders from INV to the ATH service area. INV 25 kV switchyard would also need to be expanded and additional property may be required for substation site expansion. However, offloading ATH from the system would not provide a significant increase in the GDN supply capability of the system. Please refer to BCTC's response to BCUC IR 2.125.1.
1.1 Reference: Application, page 29

1.1.1 Please clarify what area is considered to be captured by the upper Columbia Valley load. Is it the load serviced from the five distribution sub-stations: Golden, Athalmer, Radium, Spillimacheen and Parsons?

RESPONSE:

Yes, the upper Columbia Valley load is comprised of the load serviced from five distribution substations located at Athalmer, Radium, Spillimacheen, Parsons, and Golden.
1.2 Reference: Application, pages 27 & 30
   Appendix B, page 64

1.2.1 Section 3.3.1 discusses the issues associated with using circuit 60L271 to supply the Golden Substation. Are there currently issues/constraints with the supply of load to the other substations on this circuit? If so, please discuss and indicate if/how the proposed project resolves them.

**RESPONSE:**

Load at all of the substations supplied by 60L271 contribute to the issues and constraints of the transmission system in the upper Columbia Valley. However, because Golden is the largest load supplied by 60L271 and it is located at the end of the supply system to this area, it experiences the issues and constraints to a greater extent than at the other locations. The load growth in the Golden area, generally the highest in the system, will tend to exacerbate the issues and constraints in the system more than at the other substations in the system.

The proposed project, i.e., a new 230 kV transmission line from Invermere to the Golden area, resolves the supply issues and constraints by offloading Golden from the existing 69 kV supply system. This frees up capacity, both in 60L271 and Invermere Substation transformation, to meet load growth at the other substations for the foreseeable future. A second benefit provided by this new transmission line is that during outages on 60L271 between Invermere and Parsons, backfeeding supply would be available from the Golden end of the existing 60L271 transmission line via the new 230 kV transmission line from Invermere.
1.2 Reference: Application, pages 27 & 30
Appendix B, page 64

1.2.2 Page 27 states that the Invermere Substation is the principle source of supply for the area south to the Kimberly Substation via circuit 60L270. The load forecast in Appendix B only includes the “southern” substations FMT and CNL. However, Figure 3-1 suggests there are a number of other substations between INV and KBY. Please clarify which substations in the lower Columbia Valley are supplied principally by INV and circuit 60L270 and update the table in Appendix B to include all relevant substations.

RESPONSE:

The substations in the lower Columbia Valley supplied by Invermere via circuit 60L270 are FMT and CNL. Other substations south of CNL such as CRC, CRS and SKU are also supplied by 60L270; however, under normal system conditions, these other substations south of CNL are supplied from Kimberley substation via the 69 kV system from Cranbrook substation.
1.2 Reference: Application, pages 27 & 30
Appendix B, page 64

1.2.3 Is the 69 kV circuit 60L270 connected to the 230/500 kV system at a point other than the Invermere substation? If so, where and to what extent can supply through this other interconnection support 60L270 in the supply of loads in the lower Columbia Valley (i.e. south of INV)?

RESPONSE:

In addition to connection at Invermere substation via the 230/69 kV transformation, circuit 60L270 is also connected to the 500/230 kV system via a 69 kV system between Kimberley substation and Cranbrook substation.

The 69 kV system between Cranbrook and Kimberley substations can supply all of the loads in the lower Columbia Valley area normally supplied by 60L270 without any additional supply from Invermere Substation beyond the 30-year planning period, i.e., all the loads south of INV supplied by 60L270 at SKU, CRS, CRC, CNL, and FMT substations.
| Reference: | Application, pages 27 & 30  
| Appendix B, page 64 |
| 1.2.4 | Are there currently issues/constraints with the supply of load to the substations in the lower Columbia valley that are served from circuit 60L270? If so, please discuss and indicate the if/how the proposed project resolves them. |

**RESPONSE:**

There are currently no issues/constraints with the supply of load to the substations in the lower Columbia Valley that are served by 60L270.
1.2 Reference: Application, pages 27 & 30
Appendix B, page 64

1.2.5 What is the maximum load that can be serviced by the existing Invermere Substation?

RESPONSE:

The maximum system load that can be supplied by the existing Invermere substation including the losses and load supplied by 60L270, 60L271 and the Invermere distribution transformer is 106.5 MVA. (see Exhibit B-1, p. 30)
1.2 Reference: Application, pages 27 & 30
Appendix B, page 64

1.2.6 Please provide a schedule setting out the substations and the forecast load that will be principally serviced by INV after the Project is completed.

RESPONSE:

The substations that will be principally served by INV after the Columbia Valley Transmission Project is completed include INV, ATH, RDM, SPN, PSN, FMT and CNL at the 69 kV level via the INV 230/69 kV transformers and GDN at the 230 kV level via the new 230 kV transmission line from INV to the Golden area.

The load forecast for these substations is shown in Table C-2 on page 64 of the System Planning Report provided as Appendix B of Exhibit B-1.
1.2 Reference: Application, pages 27 & 30
Appendix B, page 64

1.2.7 What is the maximum load (in the upper Columbia Valley – excluding the Golden area) that can be serviced using the Invermere Substation and circuit 60L271?

RESPONSE:

Based on the transmission line’s present thermal limit and maximum conductor operating temperature, the maximum load in the upper Columbia Valley that can be served by 60L271 excluding the Golden area but including line losses is 48 MVA during the summer peak period and 68 MVA during the winter peak period between ATH and PSN. (Please see Exhibit B-1, Section 3.3.1, page 30 and Appendix B, page 11.)

For the maximum load that can be serviced by Invermere Substation, please see BCTC’s response to BCOAPO IR 1.2.5.
1.3 Reference: Application, page 31

1.3.1 Please clarify the basis for the DSM estimates used and, in particular, the level of savings is incorporated regarding rate-related DSM.

RESPONSE:

BCTC forwarded this question to BC Hydro for response. BC Hydro’s response is as follows:

The foundation for the DSM estimates reflected in the peak load forecasts is BC Hydro’s DSM Plan contained in BC Hydro’s 2008 LTAP. The DSM plan includes projected savings from programs, codes and standards and rate design such as the two tier rate structure which determines the rate related DSM savings. In addition, the load forecast with DSM also contains rate level savings (from future rate increases under a flat rate design structure).
1.4 Reference: Application, pages 32-33

1.4.1 Please reconcile the fall 2012 need date quoted here (line 28) with the winter 2009/2010 date referenced on page 30 (line 17) as to when the capacity at the Invermere Substation will be exceeded.

RESPONSE:

As indicated in Exhibit B-1, page 32, line 28, Fall 2012 is the earliest possible in-service date for the proposed project. As indicated in line 17 on page 30, the load serviced by the INV transformers exceeds the firm on-site transformation capacity with one of the INV 230/69 kV transformers out of service.

Due to the lead time requirements and the practical limitations regarding the in-service date for the proposed project, the risk of an INV transformer load will be managed by BCTC’s Real-Time Operating group if and when a transformer failure occurs; however, considering their age (30 years) and good condition, the risk of a transformer failure is low.
1.4 Reference: Application, pages 32-33

1.4.2 For each of the short-term measures discussed on page 33, please indicate the timeframe required to put them in-place.

RESPONSE:

Industrial load curtailment during winter peak load periods or an increasing marginal supply from a small distribution IPP that is already connected to the distribution system may possibly be implemented quickly subject to negotiation and agreement with relevant customers and the time to undertake the preparations necessary to modify their production processes accordingly.

The time frame required to install a battery bank storage facility in the distribution system could likely take one to two years and the time frame required to modify the system to facilitate the temporary installation of diesel generators could likely take up to half a year.
1.5 Reference: Application, page 34

1.5.1 For each of the three alternatives considered, please describe the extent to which the 69 kV system and circuit 60L271 will be used to meet load requirements at the Athalmer and more northerly Substations. Is it the same in each case.

RESPONSE:

Under normal conditions, Golden substation would be supplied by the new facilities installed under each of the three alternatives.

The 69 kV system and 60L271 would be used to the same extent to meet load supply requirements at Athalmer and the substations north of Athalmer for all three alternatives. In the event of outages on 60L271, the capacity to backfeed 60L271 via Golden, following implementation of new facilities, varies for each Alternative, as detailed at pages 35, 40, and 45 in Appendix B of Exhibit B-1.
1.6 Reference: Application, page 40
Appendix D, page 20

1.6.1 The Application states that line losses are monetized at $74/MWh. What is the basis for this value and in what year’s dollars is it quoted?

RESPONSE:
The $74/MWh figure is taken from BC Hydro’s F2006 Open Call for Power Report on the Call for Tender Process and is in constant 2006 $. The price was not adjusted to current dollars as the cost of electricity delivered under the EPAs was fixed and declined in real terms over the terms of the contracts.
1.6 Reference: Application, page 40
Appendix D, page 20

1.6.2 Please reconcile this $74/MWh value with the $117/MWh value used on the TEP analysis.

**RESPONSE:**

The benchmark energy value of $74/MWh at the plant gate was used in calculation of losses. It reflects the marginal cost of energy from new supply for the BC Hydro system at the time the CVT CPCN Application was prepared and is based on BC Hydro’s 2006 Call for Tender, as noted in BCTC’s response to BCOAPO IR 1.6.1.

This benchmark energy value was recently revised to $107/MWh at the plant gate (and $124/MWh delivered to Lower Mainland) and reflects BC Hydro’s preferred clean energy portfolio from Appendix F11, Table 1 - Estimated Unit Energy Cost Adjustment Values of the 2008 LTAP.

The TEP analysis used a value of $117/MWh derived using the 2008 LTAP, Appendix F11, Table 1 - Estimated Unit Energy Cost Adjustment Values. The TEP analysis includes delivery costs and excludes the natural gas options.
1.6 Reference: Application, page 40
Appendix D, page 20

1.6.3 What is the impact on the cost of the alternatives if the $117/MWh value is used to value losses?

RESPONSE:

Please refer to BCTC’s response to BCOAPO IR 1.6.2. The new cost for the assessment of the value of losses is $107/MW.h, effective February 2010. Changing the cost associated with the value of losses has a minimal impact on the revenue requirement impact to customers. The table below provides the present value revenue requirement impact for the load alternatives as a result of varying the value of losses using $74/MW.h, $107/MW.h, and as requested, $117/MW.h.

<table>
<thead>
<tr>
<th>Line No.</th>
<th>$ millions</th>
<th>Reference</th>
<th>Load Facilities PV Revenue Requirement F2010 - F2040</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Alt 1</td>
</tr>
<tr>
<td>1</td>
<td>Revenue Requirement before losses</td>
<td>BCUC 1.69.2 T2 (corrected), line 8</td>
<td>169.1</td>
</tr>
<tr>
<td>2</td>
<td>Losses at $74/MW.h</td>
<td>BCUC 1.69.2 T2 (corrected), line 9</td>
<td>8.6</td>
</tr>
<tr>
<td>3</td>
<td>Total Revenue Requirement with Losses at $74/MW.h</td>
<td>L2 + L1</td>
<td>177.7</td>
</tr>
<tr>
<td>4</td>
<td>% Impact to BC Hydro Revenue Requirement</td>
<td>BCUC 1.69.2 T2 (corrected), line 14</td>
<td>0.37%</td>
</tr>
<tr>
<td>5</td>
<td>Losses at $107/MW.h</td>
<td>BCOAPO 1.6.2</td>
<td>12.4</td>
</tr>
<tr>
<td>6</td>
<td>Total Revenue Requirement with Losses at $107/MW.h</td>
<td>L5 + L1</td>
<td>181.5</td>
</tr>
<tr>
<td>7</td>
<td>% Impact to BC Hydro Revenue Requirement</td>
<td></td>
<td>0.38%</td>
</tr>
<tr>
<td>8</td>
<td>Losses at $117/MW.h</td>
<td></td>
<td>13.6</td>
</tr>
<tr>
<td>9</td>
<td>Total Revenue Requirement with Losses at $117/MW.h</td>
<td>L8 + L1</td>
<td>182.7</td>
</tr>
<tr>
<td>10</td>
<td>% Impact to BC Hydro Revenue Requirement</td>
<td></td>
<td>0.38%</td>
</tr>
</tbody>
</table>
1.7 Reference: Application, page 42
BCUC 1.36.5

1.7.1 Please confirm whether the “unavailability” (hours/year) values shown in Table 4-5 are based on the same definition as those discussed on page 31. Is it fair to conclude that under Alternatives 1 and 2 the reliability will be higher than the average for all 69 kV south interior lines?

RESPONSE:

Yes, the “unavailability” (hours/year) values shown in Table 4-5 are based on the same definition as those discussed on page 31.

Yes, it is fair to conclude that the reliability of Alternatives 1 and 2 will be higher than the average for all 69 kV South Interior lines, normalized for circuit length.
1.7 Reference: Application, page 42

BCUC 1.36.5

1.7.2 Please provide similar average reliability statistics for all existing 230 kV lines.

RESPONSE:

The average reliability of all existing 230 kV overhead transmission lines in the BCTC system is shown in the table below. The values in the table below are based on 10-year outage statistics (F1999-F2008).

<table>
<thead>
<tr>
<th>Area</th>
<th>Failure Frequency (failure/year/100km)</th>
<th>Repair Time (hours)</th>
<th>Unavailability (hours/year/100km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BCTC</td>
<td>0.33</td>
<td>18.28</td>
<td>6.11</td>
</tr>
</tbody>
</table>
1.7 Reference: Application, page 42
BCUC 1.36.5

1.7.3 With respect to BCUC 1.36.5, what is the “unavailability” (hours/year) value associated with the single 230/69 kV transformer option?

RESPONSE:

With respect to BCUC IR 1.36.5, the “unavailability” (hours/year) value associated with the single 230/69 kV transformer option is 9.6464 hours/year (resulting in EENS = 1451.2 MWh/30 years).
1.8 Reference: Application, page 64  
BCUC #1.30.5 & 1.30.6

1.8.1 Please describe what the determining factors will be in any decision to divert the transmission route in order to avoid the Toby Creek Crossings.

RESPONSE:

BCTC has evaluated the Toby Creek diversion and filed a Supplement to the Application for a Certificate of Public Convenience and Necessity, dated 20 April 2010 (Exhibit B-6).

The Supplement details the key relevant factors considered in BCTC’s decision making process with respect to the diversion route.
1.9 Reference: Application, page 72

1.9.1 Based on BCTC’s understanding of stakeholder concerns, please prepare a comparison similar to that presented in Table 5-2 but with respect to the various options for Segment 2.

RESPONSE:

BCTC has finalised the route for this segment after further property investigations and discussions with the Town of Golden. The route is a variant of Option 4 (preferred route), with the only difference being the 69 kV transmission line is sited on the east side of the Highway 95 instead of the west side. Please see attached map.

As noted in Exhibit B-2, page 72, the proposed option is similar to the other overhead alternatives with respect to environmental impacts, length, and cost to other overhead alternatives. Further, the route has the support of the Town of Golden, CP Rail, and MOTI. For these reason BCTC has identified Option 4, with the variant noted above, as the preferred route option of Segment 2.
Attachment to BCOAPO IR 1.9.1

**NOTE:**

1. Total T/L Length 3.1 Km
2. Total No. Of Structures 35.
3. Span Length Over The Columbia River 140m-160m
4. Span Length Over The Rail Yard 160m.
5. Span Length Over The Kootenay Colombia HWY 100m.
6. Average Span Length 90m
1.10 Reference: Application, pages 85-100
Application, page 80

1.10.1 To what extent does the cost estimate set out on page 80 account for the costs of the various mitigation measures described in Section 6.1? Please discuss with reference to each of the six component areas.

RESPONSE:

For each of the component areas in Section 6.1, the costs have generally been accounted for in the estimate through preliminary design and contingency analysis. Costs impacts of these measures are not extraordinary and are typical of many transmission projects.
1.11 Reference: Application, pages 176-177
BCUC #1.51.1

1.11.1 Please provide an update regarding any additional feedback or concerns received from First Nations since the Application and the responses to the BCUC round #1 interrogatories were filed. Please provide BCTC’s response and/or plans to address any issues raised.

RESPONSE:

BCTC forwarded this question to BC Hydro for response. The following is BC Hydro’s response:

A supplemental filing of evidence regarding First Nations consultation will be filed with the BCUC on 7 May 2010. BC Hydro will provide the information requested with that filing.
1.11 Reference: Application, pages 176-177
BCUC #1.51.1

1.11.2 Please summarize what, in BCTC’s view, are the outstanding First Nations’ issues remaining to be resolved.

RESPONSE:

This question was referred to BC Hydro for response. The following is BC Hydro’s response:

BC Hydro has entered into a Benefits Agreement with the Shuswap Indian Band and, as such, all issues with the Shuswap have been resolved.

BC Hydro continues to participate in consultations and negotiations with the KNC. At this time, BC Hydro does not believe it is appropriate to disclose the substance of the negotiations. The consultation record will be updated with the 7 May 2010 filing of additional First Nation evidence.

BC Hydro can advise that BCTC has decided to re-align the transmission line route due, in part, to a request from KNC that a re-alignment of the route be considered that would avoid the crossing of Toby Creek.

The Lakes District and its member First Nations have not communicated any specific concerns to BC Hydro, other than a desire for “government to government” discussions. BC Hydro will update the consultation record with the 7 May 2010 filing of additional First Nation evidence.
1.11 Reference: Application, pages 176-177
   BCUC #1.51.1

1.11.3 Do the project costs set out on page 80 include funding to cover the
cost of consultation (including capacity funding) with First Nations? If
yes, does the cost allowance adequately cover the projected costs for
these activities?

RESPONSE:

Yes, the cost estimate set out on page 80 includes funding to cover the cost of consultation
(including capacity funding) with First Nations.

Yes, BCTC believes the project cost estimate adequately covers the costs for these activities.
1.1.0 Reference: BCTC response to BCUC IR 1.5.1, February 18, 2010

TOPIC: Consequence of delays

1.1.1 What is the probability distribution (duration, energy gap (load v. capacity)) for load exceeding the 29 MVA threshold at the Golden substation (GDN) area during winter 2011-2012, both with and without the interim storage battery solution currently being implemented?

RESPONSE:

The P50 load forecast included and described in Exhibit B-1 at page 28.

Based on past winter load profiles, the GDN load could exceed the 29 MVA capacity threshold by 1.7 MVA for approximately 60 hours during the winter of 2011-2012. Depending on the specific implementation, a 2 MW storage battery may be sufficient to meet this peak load requirement. However, it will not be sufficient to meet the peak load beyond F2012.
1.2.0 Reference: BCTC Application, sec. 5.9, Revenue Requirement Impact, pp. 82-83

TOPIC: Provincial government revenues and revenue-sharing

Table 5.6 indicates total estimated annual grants and taxes for the project of $0.6 million.

1.2.1 What are the anticipated revenues to the provincial government as a result of the construction and operation of the transmission line? What rental or lease payments will be made to the government for the use of the crown land right of way? What is the incremental amount of dividend that will be paid by British Columbia Transmission Corporation (BCTC) to the provincial government as a result of the operation of the new transmission line?

RESPONSE:

The estimated fees and taxes to the provincial government that BCTC can calculate with some degree of accuracy as a result of the construction and operation of the CVT Project are:

(a) Estimated one time fees of $2.4 million included in the capital cost for:

   i. *Land Act* fees for Crown Statutory Rights-of-Way and Licence of Occupancy, $0.6 million

   ii. Stumpage Fees, $1.8 million;

(b) Ongoing school taxes payable under section 34(2) of the *Hydro and Power Authority Act* reflected in the estimate shown on Table 5-6, $0.6M.

(c) The CVT Project will not result in BCTC making any dividend payment to the Province.

BC Hydro advises that because many factors outside of the Project impact the amount of its dividend payment to the Province, BC Hydro cannot provide an estimate of its dividend payment directly attributable to the Project.

The estimated revenues to the provincial government above will also depend on the actual design and assets constructed. The estimated revenues to the provincial government above will also depend on the actual design and assets constructed.
1.3.0 Reference: BCTC Application, sec. 8.2, Role of BC Hydro, pp. 139-140

TOPIC: Roles of BCTC and BC Hydro vis-à-vis First Nations

1.3.1 What provisions, if any, of the Asset Management and Maintenance Agreement or any of the other “designated agreements” between BCTC and the British Columbia Hydro and Power Authority (BC Hydro) would be breached if BCTC were to become a party to certain agreements, such as impact management and benefits agreements, that are currently being negotiated between BC Hydro and First Nations?

RESPONSE:

None of the provisions of the Asset Management and Maintenance Agreement (AMMA) or of the designated agreements would be breached, per se, if BCTC were to become a party to an impact management and benefits agreement with a First Nation. Conceivably, a particular term of such an agreement might in some circumstance be inconsistent with the Master Agreement, AMMA or the other designated agreements.

Section 5.1 of the AMMA between BC Hydro and BCTC dated 12 November 2003 states that “At all times during the term of this Agreement, BC Hydro will continue to be responsible for the relationship between BC Hydro and First Nations with respect to the Transmission System including... (b) negotiating protocols and agreements with First Nations in connection with the Transmission System, including protocols and agreements relating to local issues, community development and consultation”.

The purpose of the agreements between BC Hydro and BCTC, including the AMMA, are to provide role clarity between the organizations as it pertains to the management of the transmission system owned by BC Hydro.
1.3.2 What is the policy justification for BCTC directly entering into procurement agreements with First Nations, but not impact management and benefits agreements?

RESPONSE:

Under the Master Agreement, BCTC has the authority and responsibility for constructing transmission that will be owned by BC Hydro. CVT is an example of such a project. The responsibility for the construction of the project includes procurement. As such, in the key agreements between BCTC and BC Hydro, BCTC has the authority and responsibility for entering into contracts with First Nations and non-First Nation contractors. Under Article 5 of the Asset Management and Maintenance Agreement, BC Hydro is fully responsible for the consultation with First Nations, which, where appropriate, may include entering into a benefits agreement. While a component of a benefit agreement may include a procurement opportunity, BC Hydro has the obligation to ensure that the terms and conditions of any benefits agreements with First Nations are fulfilled by BCTC or any other party.

Please also refer to BCTC’s response to Ktunaxa Nation Council IR 1.3.1.
1.3.0 Reference: BCTC Application, sec. 8.2, Role of BC Hydro, pp. 139-140

TOPIC: Roles of BCTC and BC Hydro vis-à-vis First Nations

1.3.3 What is the policy justification for establishing and maintaining a division of responsibilities between two Crown agencies that deprives First Nations of privity of contract with a Crown agency (i.e. BCTC) that is the proponent of projects with the potential to seriously impact on Aboriginal title and rights?

RESPONSE:

This question was forwarded to BC Hydro for response. Following is BC Hydro’s response:

Under the Master Agreement and associated agreements between BC Hydro and BCTC, BC Hydro is responsible for First Nations policy matters.

BC Hydro is of the view that privity of contract is not of any practical significance because BC Hydro, as the owner of the transmission system and the signatory on the agreements with First Nations, is contractually responsible for ensuring that all obligations under benefits agreements are performed. This is regardless of whether these benefits flow through the Crown Corporation responsible for planning, operating and maintaining BC Hydro’s transmission system or a contractor.
TOPIC: First Nations Consultation Approach

The application states: “BC Hydro’s consultation efforts on the CVT Project have been and are to ensure that identified First Nations whose asserted Aboriginal rights or title may be affected by the CVT Project are provided with appropriate information to understand the nature of the CVT Project...and to ensure that the potential adverse and beneficial impacts on First Nations’ interests are clearly understood by BC Hydro, BCTC and First Nations.”

1.4.1 If the above quote reflects the objectives for BC Hydro’s consultation efforts, which organization (BC Hydro or BCTC) is responsible for addressing, through mitigation, compensation or other accommodation measures, the potential adverse impacts on First Nations’ interests?

RESPONSE:

As between BCTC and BC Hydro, BC Hydro is responsible for ensuring that any duty that the Crown may have to consult with, and where necessary accommodate, First Nations with respect to any transmission capital project is met.
TOPIC: Completion of First Nations consultation

1.5.1 What components of consultation with First Nations does the proponent intend to undertake and complete after the deadline for the BCTC final submission (May 28, 2010)?

RESPONSE:

This question was referred to BC Hydro for response. BC Hydro’s response is as follows:

BC Hydro’s commitments to ongoing and future consultation with all First Nations potentially affected by the Project can be found in Section 8.8 (page 177) of Exhibit B-1.

Specific to the KNC and its member First Nations, BC Hydro intends to undertake and complete the following after the deadline for the BCTC Final Submission (28 May 2010):

(a) on-going consultation to consider ways of providing benefits during construction of the Project to KNC and its member First Nations, including employment and procurement opportunities;

(b) continue to work towards avoiding or mitigating impacts to the extent reasonably possible; and

(c) continue information sharing and dialogue with the KNC through studies such as the AIA and the AUIS, as well as the construction EMP in order to assist in the detailed design process.
1.1 Is a second 230 kv or any additional line from Cranbrook to Invermere in the planning stages or will one become necessary in the 30 year study plan?

If this line were expected to be necessary how soon and what would be the estimated cost? Is this cost included in the formula of the most cost efficient route? Identify the network configuration required to cater for longer-term development and define the scope of the initial development to allow for long-term plans, including IPPs.

RESPONSE:

There is no second 230 kV transmission line or any additional transmission line from Cranbrook to Invermere in the planning stages and one would not be required in the present 30-year planning period based on the present long-range load forecast.
1.2 Identify the principal developments and their load magnitude comprising the high/low load forecasts for the Columbia Valley area.

Is Jumbo Glacier Resort included in the growth forecast? Is the Panorama Mountain Village expansion in the growth forecast? Is the Kicking horse Ski Resort expansion that was just announced by our Premier in the growth forecast? Is the growth estimate of Golden area rated at 2.9% or 4.0%? The Growth in the entire Columbia Valley area in the last three years before the recession certainly exceeds these estimates and this trend is expected to continue as we come out of the recession. Have the growth estimates been brought up to date as in the last three or four years instead of the last 30 years?

RESPONSE:

BCTC forwarded this question to BC Hydro for response. BC Hydro’s response is as follows:

The load forecast, as shown in Exhibit B-1, Appendix C of Appendix B included known spot loads (identifiable larger customers) in the Columbia Valley, including major anticipated developments such as Jumbo Glacier Resort and Kicking Horse Ski Resort. Panorama Mountain Village expansion was not added at the time that the forecast was released. Spot loads are considered in addition to the general load growth in the load forecast. Average annual growth for Golden is 2.9 percent for the study period. The load forecast is updated on an annual basis and recent growth trends are considered.

It is BC Hydro’s policy not to disclose details on its customers, including projected customer load information. BC Hydro has provided a document showing principle developments in the Columbia Valley Area over the period F2009 to F2019 to the Commission as CONFIDENTIAL Attachment 1 to this IR response. Confidential Attachment 1 also includes supplementary information showing the forecast load for the Panorama Mountain Village expansion.
1.3 As the peak of Hydro Carbon fuel occurs and a massive switch to electric power for vehicles and gas or diesel guzzling motors occurs, is this power consumption included in the 30 year forecast?

RESPONSE:

BCTC forwarded this question to BC Hydro for response. BC Hydro’s response is as follows:

BC Hydro has been active in studying the potential effects of electric vehicles (EVs) on its system. In its 2008 LTAP Application, BC Hydro provided a high level estimate of the effects of EVs on its load as a scenario.

In the 2008 reference peak and energy forecasts, BC Hydro did not assume that the provincial vehicle fleet would be substantially electrified. To make this assumption would require greater certainty in terms of enabling technologies (such as recharging infrastructure). The load forecasts contained in the 2008 LTAP were approved by the Commission.
1.4  (Appendix C World energy picture) Hydro Generation only has enough water to run at 58% of capacity.

Conservation of energy is a necessity in the global welfare of the future and the Mica to Golden route would be even more efficient with a 230 kV line. Why was the most energy efficient route not chosen and therefore reduce the need for new dams in the light of even less water with global warming reducing our annual precipitation in the future?

Coupled with the interconnection of IPP’s and energy savings why was this line not considered as the most preferred line being that it will pay for the extra original cost in saved energy and the need for more power lines in the near future? 185 KV is a nonstandard voltage for transmission systems. Why has it been proposed in this particular case?

RESPONSE:

The Mica to GDN route with a 230 kV transmission line was not chosen because of high capital cost and reliability considerations.

Capital costs include both a lengthy 230 kV transmission line and the associated 500/230 kV substation development required for a Mica to Golden alternative. Alternative 3 (138 kV MCA-Golden), does not compare favourably with other alternatives (see Exhibit B-1, page 40) and a 230 kV Mica to Golden alternative does not fundamentally change the economic assessment.

A second reason for not selecting the Mica to Golden option was based on reliability concerns. Some sections of the transmission line would be routed through rugged terrain susceptible to the possibility of landslides or avalanches. At least one high mountain pass would need to be traversed (Moberly Pass) in which the transmission line would be exposed to extreme weather conditions with potentially severe access constraints, particularly in winter. Any outages due to these causes would have the potential to be long-term outages due to these factors which could result in an extended period of load curtailment for the customers in the upper Columbia Valley due to the limited supply capability of the existing system. (See Exhibit B-1, Appendix B, page 48)

A 185 kV voltage level was not proposed for Columbia Valley Transmission Project purposes because it is a non-standard voltage level. The transmission line options considered were based primarily on new transmission line construction rated 230 kV, 138 kV or 69 kV, all standard voltage levels for transmission purposes.
1.5 Can you show us a diagram or chart of line losses per km. on 185 kv verses 230 kv. lines? What is the actual line energy loss in the Route from Selkirk or wherever the actual power is generated to Cranbrook, then to Invermere, then to Golden? What is the actual line energy loss in the 185 kv proposed line from Mica to Golden? What would be the line energy loss in a 230 kv line from Mica to Golden and why was it not proposed? One of the main reasons for this 185 kv line alternate being not chosen is that it would not be adequate past the study time. Would a 230 kv. line be adequate after the 30 year study and maybe necessary even before?

RESPONSE:

BCTC did not study a transmission line option based on a voltage level of 185 kV for this project because this is a non-standard transmission level voltage. The voltage levels proposed for all alternatives with this project were 230 kV or 138 kV.

The energy loss in a transmission line is equal to the product of the square of the current flowing through the transmission line and the resistance of the transmission line. Assuming the same conductor is installed over the length of the transmission line, the resistance will be the same for each kilometre of the line and, assuming a constant current in the transmission line, the losses incurred would be the same for each kilometre. Consequently, a chart showing the transmission line losses per kilometre would be a straight horizontal line with a constant energy loss equal to \((I^2 \times R)\) for each kilometre of the line. The total energy losses over the transmission line would be equal to the sum of the losses over each kilometre, or for the conditions indicated above, the losses over 1.0 km multiplied by the length of the transmission line in kilometres.

The transmission line energy losses in the route from the generation sources to Cranbrook, then to Invermere, then to Golden are dependent on several factors including system load and generation conditions and can vary significantly on a daily basis due to the daily load/generation cycles over the entire route as well as on a seasonal basis due to changing seasonal conditions. In particular, the generation in the Kootenay area flows over a meshed network to Cranbrook and the energy losses over this portion of the route can depend on the status of the transmission system, the generating capability of each generating station at any given time, and the total system generation required to meet import or export commitments.

BCTC’s system loss calculation methodology is set-out in Exhibit B-1, Appendix B, page 17.

The annual peak-load losses over the requested sections of the route from Cranbrook to Invermere and from Invermere to Golden for the first year, the middle year and the last year in the long-range planning period are as follows (see also BCTC’s response to BCUC IR 1.17.1):
Lake Windermere District Rod and Gun Club Information Request 1.5
Dated 16 March 2010
British Columbia Transmission Corporation Response Issued 30 April 2010

<table>
<thead>
<tr>
<th>(MW)</th>
<th>2012/13</th>
<th>2025/26</th>
<th>2038/39</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Alternative 1: INV-Golden 138 kV line losses</td>
<td>0.8</td>
<td>1.5</td>
</tr>
<tr>
<td>2</td>
<td>Alternative 2: INV-Golden 230 kV line losses</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>3</td>
<td>Alternative 3: MCA-Golden 138 kV line losses</td>
<td>1.4</td>
<td>2.6</td>
</tr>
<tr>
<td>4</td>
<td>MCA-Golden 230 kV line losses</td>
<td>0.6</td>
<td>0.8</td>
</tr>
</tbody>
</table>

The Mica to Golden transmission line option wasn’t selected for the reasons provided in BCTC’s response to Lake Windermere District Rod and Gun Club IR 1.4.

A 230 kV line would be adequate to provide capacity over the study period.
1.6 (Appendix C Carbon Footprint of Renewables) **Hydro storage 10g of CO2 emissions per KW/hr.**

(Transmission System Losses) **4.2.1.1 graph** shows that the proposed 185 kv.line from Cranbrook to Invermere has expected losses of 5.75 in 2025. and **4.2.2.1 graph** shows that the same line only with a 230 kv. line has expected losses of 4.48 in 2025, a savings of 1.27 just in the 185 to 230 kv. line voltage. **4.2.3.1 graph** shows that the proposed 185 kv. line from Mica to Golden has expected line losses of 2.59 in 2025. Can you please show these line losses in kw/hrs. or mw/hrs?

Since these graphs have only a number shown and not in kw/hrs. or mw. or % we have no idea of actual losses except that a 185 kv line has greater losses than a 230 kv. line and the Mica to Golden proposal has significantly less loss than other alternatives.

What would the expected line losses be if the proposed line from Mica to Golden was a 230 kv. line in kw?hrs. or mgw/hrs?

What would be the extra estimated cost?

What would be the savings of CO2 emissions?

With Green energy being a priority and reducing pollution being a very important factor in reducing global warming, would the most energy efficient route be the most preferred route over the least expensive route as the most energy efficient route would most likely pay for this additional cost over time and be far less wasteful?

**RESPONSE:**

BCTC did not propose a 185 kv transmission line option for this project because it is a non-standard transmission level voltage. The tables for the 185 kv options referred to above are based on the 138 kv options considered for this project.

The loss data provided in the referenced charts refers to the MW losses incurred during the annual peak load period (see Exhibit B-1, Appendix B, pages 36, 41 and 46). This data allows the losses for the various options to be compared.

The present value cost of the total energy losses is included in Exhibit B-1, Appendix B, pages 65, 66 and 67. The approximate total energy losses (MWh/year) in 2025 for the three alternatives indicated above as well as for a 230 kv line from Mica to Golden are provided in the table below.
The total capital cost for the Mica to Golden alternative based on a 230 kV transmission line and including the 500/230 kV substation development associated with this alternative is approximately $304 million (estimate has an accuracy of -50%/+100% and includes IDC, overhead and contingency). The net present value of this alternative is approximately $60 million higher than that of the 138 kV option from Mica to Golden.

The savings in CO₂ emissions have not been calculated for this option. Any savings in CO₂ emissions would require a detailed study including assumptions concerning future generation options, including thermal generation using oil, gas, wood-waste or other similar fuels.

Many factors need to be considered in the evaluation of route options including financial factors such as the capital cost of the project, rate impacts, technical considerations such as system reliability, environmental and socio-economic impacts, and First Nations issues. Energy efficiency is accounted for in the economic analysis of the projects.
1.7 The 185 kv. proposal or a 230 kv from Mica to Golden would pass by several IPP’s, is there a possibility that a portion of the cost of this proposal could be recovered from the IPP projects either now or in the future as when they come on line, this line although it may be a lower voltage would become necessary and at the IPP producer’s cost? Has this avenue been explored?

RESPONSE:

Under BCTC’s Open Access Transmission Tariff (OATT), BCTC is required to upgrade the transmission system to meet customer requirements in a manner that is safe, reliable, and cost effective. BCTC is proposing the CVT Project to serve anticipated electricity demand in the upper Columbia Valley. In accordance with BCTC’s OATT, the cost of network upgrades to meet these energy needs would be recovered from transmission rates.

During the planning and analysis of the CVT Project, no IPP projects have been sufficiently advanced to explore the type of discussion suggested by the question. Given their uncertainty, BCTC has not considered the possibility of capital cost contributions from IPP projects with respect to any alternative. In addition to the cost of the transmission line, integration of IPP projects includes additional incremental costs. Exhibit B-1 Section 4.2 discusses the inherent risks of the Mica to Golden alternative which was rejected for reasons contained in Exhibit B-1.
1.8 (Binder 1 B 2.3 page 12 Other Considerations) System Reliability

If there was a forest fire or any interruption of power South of Invermere or between Cranbrook and Selkirk Substation or anywhere in the single route to Invermere would there be a very long loss of power to the entire Columbia valley?

Would a second source of power into the Columbia Valley at the Northern end of the Columbia Valley and thus becoming a two circuit radial system be a much more reliable system with a future upgrade to the existing power line from Invermere to Golden of which 62.7 kms. are already 138 kv. and the remaining 66.1 kms only remaining to be upgraded?

This alternate route from a second source would complete a very important grid into the entire Columbia Valley and beyond in case of any disaster or collapse of a Generation system.

RESPONSE:

The entire Columbia Valley would experience an outage for events south of Invermere only if the event removed from service both the 230 kV and 69 kV transmission lines from Invermere to Cranbrook or both the 500 kV line and 230 kV line from Cranbrook to Selkirk. However, these systems have high a degree of reliability and there is low probability of a coincident outage to two circuits.

In regards to the loss of both transmission lines between Invermere and Cranbrook, these lines are located on separate rights-of-way over most of their length with the 69 kV transmission line located primarily on the east side of the Columbia River and the 230 kV line located on the west side of the river, a natural barrier that helps impede the expansion of a forest fire. Further, there are highways or roads on both sides of the river that provide good access for fire fighters as well as transmission line repair crews. Consequently, the probability of losing both circuits due to an event such as a forest fire is low (refer to BCTC’s response to Lake Windermere District Rod and Gun Club IR 1.12).

The worst-case single-contingency outage would be the loss of the 230 kV transmission line. In this case, the 69 kV transmission line supplying the upper Columbia Valley would be automatically tripped out of service to avoid a system voltage collapse and the entire upper Columbia Valley would lose supply until the line could be restored to service. The lower Columbia Valley would retain supply during this outage. The load that could be served in the upper Columbia Valley with the 69 kV line restored would depend on system loading conditions at the time of the outage and could be limited to essential services in the upper Columbia Valley.
Valley until the 230 kV line could be restored to service. The duration of the 230 kV line outage would depend on the nature of the event that removed the line from service and the damage incurred by the transmission line. The worst-case scenario would likely be a forest fire in summer; however, as indicated above, the transmission line is located in a well-developed corridor with good transportation venues and access to the transmission line. Consequently, fire-fighting efforts and the ability to repair and restore the line to service would be enhanced by its location and the access available.

In regards to the loss of both transmission lines between Cranbrook and Selkirk, sections of these lines are located on common rights-of-way or rights-of-way in close proximity to each other. Consequently, there is a higher probability that both of these lines could be forced out of service coincidentally. If this were to happen, supply to the Cranbrook and Columbia Valley would likely be restored fairly quickly by importing power over the 500 kV inter-utility tie line between BC and Alberta. If one of the circuits was to be forced out of service, BCTC’s Real-Time Operations group would prepare contingency plans with the Alberta utility to either ensure supply could be maintained to the affected areas or re-established quickly if the second line was to be forced out of service.

A second source of supply into the Columbia Valley at the northern end of the valley has limited ability to supply the entire Columbia Valley due to the length of the transmission distance involved. (See Exhibit B-1, page 41.) Load curtailment would be required in the upper Columbia Valley due to the limited ability of the existing 69 kV system to supply load in this area with the load curtailment required increasing with area load growth. Further, a Mica to Golden line would be less reliable than the 230 kV system as proposed by the CVT Project (see Exhibit B-1, page 42).

Following implementation of a solution to enhance supply to the upper Columbia Valley, any future upgrades, such as conversion of the existing 69 kV system from Invermere to Golden would be evaluated based on the system needs at that time.
1.9  To allow for a better route and more time for building the most reliable and energy efficient Route could the existing line of which the portion from Golden to Spillimacheen is already 138 kv. and the remaining 66.1 kms. is 69 kv. be upgraded to a complete 138 kv. line from Invermere to Golden on the existing right of way and in time for the extra load for Golden area.

RESPONSE:

Please see BCTC’s response to BCUC IR 1.14.6.
1.10 Impacts on Mountain Goats in the Toby Creek area are noted as low and are being dismissed with little consideration of the opposition of many stakeholders. Have the cumulative impacts even been considered of future lines like a second 230 kv. line from Cranbrook, the Glacier / Howser IPP line, the Jumbo Glacier Resort Line and any other feeder lines in or out of the Invermere Substation that may become necessary in the future?

If all these lines are to cross Toby Creek twice it would leave no un-cleared area on the south side of Toby. Is there enough area to accommodate all these lines as they become necessary if this double crossing is allowed?

**RESPONSE:**

The CVT Project as proposed does not trigger an environmental assessment under the *Canadian Environmental Assessment Act* and thus does not require a cumulative impacts assessment study. BCTC retained AECOM to conduct a detailed environmental overview assessment for this project, which has been submitted at Exhibit B-1, Appendix N. AECOM has concluded that with the implementation of recommended mitigation measures, the overall impact of the CVT Project on the environment is low.

Currently, BCTC has no plan or schedule to build a second 230 kV line from Cranbrook to Invermere. Please see Lake Windermere District Rod and Gun Club IR 1.1.

With respect to the BCTC’s evaluation of a route to avoid crossing Toby Creek, please see Exhibit B-6, a Supplement to the CVT CPCN Application – Toby Creek Diversion, filed 20 April 2010.
1.11 An alternate route on the north side of Toby Creek has been proposed and has been marked with GPS waypoints identifying this route. It would not require any private land right of ways, is shorter than the proposed route and can be built with less or the same amount of corners. It would be less visable than the existing line from Invermere substation to Athalmer. It would totally avoid the protected Toby Creek Mountain Goat herd. It is barely mentioned in this application.

Why is this small change of the route not being considered and marked in the application with so many stake holders all in favor of this change?

We cannot leave this until after the application has passed to be explored. This has come up in the open houses and we feel it must be fully explored before the passing of this project.

**RESPONSE:**

Please see the Exhibit B-6, a Supplement to the CPCN Application, Columbia Valley Project – Toby Creek Diversion, filed 20 April 2010.
1.12 **BCTC Southern Interior Regional Transmission System Reinforcement Options May 24 2006 information Release**

Following the forest fires in the summer of 2003, which resulted in several communities in the North Thompson Valley being left without power supply for over a month due to the loss of the 138 kv line supplying that area, the BCUC requested the BCTC to review the option available to reinforce or otherwise improve the reliability of supply to major load centers supplied by single-circuit radial systems. One of the options available to reinforce supply to WBK would be to construct a second 185 kv line interconnected to Fortis BC system in the Kelowna area.

Being the Columbia is served by a single-circuit radial system and a forest fire of the statue of the Kelowna fire could occur in the Columbia Valley or between Selkirk and Cranbrook, would it not be a much more reliable system to be connected to a second source with a line at the other end of the Columbia Valley?

**RESPONSE:**

Please see BCTC’s response to Lake Windermere District Rod and Gun Club IR 1.8.
Please explain what BCTC is hiding as when Mr. Deepak Anand was asked if there was a second line from Cranbrook to Invermere in the planning he stated that there was none in the 10 year plan

**BCTC website / Regional Studies / Southern Interior / IPP Generation Transfer Capability From Golden to Cranbrook. / dated 3 March 2005 / 8.0 system Development Plans**

The Report states that; “A second CBK-INV 230kv transmission line has been in our ten year system plan for approximately 20 years to improve the reliability of supply to the upper Columbia Valley area.” If the 230 kv line from Invermere to Golden as in the preferred alternative was built would this second 230kv line from Cranbrook become immediately necessary or how soon would it be necessary? It also mentions a 230kv line 310 kms from Mica Dam to Invermere as a means to integrate IPP developments in this area and states; “The cost of this project could easily exceed $100 million.”

Please explain why in 2005 a 230 kv line from Mica Dam to Invermere 310 kms long has a cost estimate of over $100 million and now in 2009 your cost estimate for a 185kv line from Mica to Golden only 220kms. long cost estimate is over $180 Million? Please note that the kms do not match, as it is 120kms from Golden to Invermere, not 90kms but these kms are from the reports.

**RESPONSE:**

BCTC was not hiding anything when Mr. Deepak Anand stated there was no second transmission line from Cranbrook to Invermere in the BCTC 10 year Capital Plan. BCTC had included a project for some time up to 2005; however, this project was removed from the Capital Plan in 2006/2007 due to the high reliability demonstrated by the existing 230 kV transmission line with sufficient supply capacity to the area over the long-range planning period.

The early cost estimate quoted for the 230 kV transmission line in 2005 was intended to illustrate an order of magnitude minimum estimate whereas the cost estimate provided for Alternative 3 for the Columbia Valley Transmission Project study was prepared in 2009 and had an accuracy of -50%/+100%. Please see BCTC’s response to Lake Windermere District Rod and Gun Club IR 1.1 with respect to a 230 kV line from Cranbrook.
1.14 Please explain why a 230 kv line from Mica to Invermere at a 2005 cost estimate of over $100 million and would provide for IPP integration and totally complete a reliable power grid throughout the Columbia Valley and be a very energy efficient line is not a number one option? (see #13 websites) A 230 kv line from Invermere to Golden plus a second line from Cranbrook to Invermere would surely cost well over 230 million so please explain how this option can be the most cost effective especially when this route has the greatest line losses and we should be most concerned in the most energy efficient option?

RESPONSE:

Please refer to BCTC’s responses to Lake Windermere District Rod and Gun Club IRs 1.4, 1.5, 1.6, 1.8, and 1.13, and Exhibit B-1 generally at Section 4 and Appendix B.
Please explain why a 230 kv line from Mica to Golden and the completion of a 185 kv upgrade to the 66 km portion Invermere to Spillimacheen of the existing Invermere to Golden line would not be the most preferred option?

RESPONSE:

A 230 kv transmission line from Mica to Golden and an upgrade of the 66 km section of the existing Invermere to Golden transmission line between Invermere and Spillamacheen to 138 kv is not the preferred option because it significantly overbuilds the transmission system and thus would not be a cost effective approach to meet the identified needs during the planning period.
1.16 The power line from MICA to NICOLA is through rough terrain. What is the maximum elevation on this line?

What is the reliability factor on this line?

What is the highest elevation line in Canada, over which pass, maximum elevation reached, and reliability factor?

RESPONSE:

500 kV transmission circuits are generally very reliable and they have greater reliability than other circuits in lower voltage classes. This is due to the fact that all the 500 kV transmission circuits deliver bulk power and connect to the major supply points to form the back bone of the transmission system. Therefore, the design of 500 kV transmission facilities (structure, conductors, insulators, etc.) has a very high standard that can withstand extreme weather conditions to some great extent, which is different from lower voltage transmission facilities with less expensive designs.

The reliability of power lines from Mica to Nicola is indicative of 500 kV transmission reliability. The reliability factor for power lines from Mica to Nicola is approximately equal to 1.0. The maximum elevation of power line from Mica to Nicola is 1709 meters.

BCTC does not have information on what is the highest elevation line in Canada. The highest elevation line in BCTC system is circuit 1L274 (1951 meters) and the second highest elevation line is circuit 2L294 (1926 meters). Both circuits are located in South Interior region.

It is important to note that the maximum elevation alone may not be indicative of circuit reliability. The terrain through which the circuit passes is also an important factor. Although circuit 1L274 is the highest elevation line in the BCTC system, it was built on a smooth terrain from south to north along a valley and does not traverse the mountains. Based on an outage frequency, the reliability of circuit 1L274 is 5.78 times worse than the average of 138 kV circuits in South Interior given the same length being considered. In contrast, circuit 2L294 (the second highest elevation line) traverses rugged terrain from east to west crossing the mountains. Based on an outage frequency, the reliability of circuit 2L294 is 7.71 times worse than the average of 230 kV circuits in South Interior (normalized for length). Since the elevation of circuits 1L274 and 1L294 are relatively similar, this historical outage information suggests that a circuit traverses rugged terrain crossing the mountains (like circuit 2L294) is likely to have a poorer reliability than a circuit that passes through smoother terrain (like circuit 1L274).
In addition to elevation and rugged terrain, the design of the circuit also plays an important role on the circuit reliability as noted above for the design of the 500 kV bulk transmission circuits.
1.17 Weeds! After speaking to Phil Burke, the Invermere employee of Mountain View Resources, the Company that holds weed control contracts and specialize in noxious weed control, we have found out that B.C.Hydro does not support any noxious or invasive weed control in this area. Are the taxpayers expected to repair the damaged terrain and control the noxious and invasive weeds that are certain to appear along the disturbed right of ways and construction areas of the new power lines?

RESPONSE:

BCTC actively works with regional invasive plant committees, regional districts, and the Ministry of Forests and Range (MOFR) throughout the Province to assist in coordination and control of noxious weed outbreaks on private properties and Crown lands over which the transmission system crosses. BCTC contributes funding to these groups. BCTC is also a member of the Invasive Plant Council of BC (IPCBC).

The proposed CVT Project is located in the Columbia Shuswap Regional District (CSRD) and Regional District of East Kootenay (RDEK). Noxious weed control is coordinated by the CSRD within its area. The CSRD has a Noxious Weed Inspector on staff. In the RDEK area, BCTC works with the East Kootenay Invasive Plant Council to coordinate control of noxious weeds.

On private lands, the landowner is responsible to control noxious weeds. BCTC works with landowners to assist them in their efforts.

On Crown land, BCTC works with, and provides funding to, the Ministry of Forests and Range, Range Branch to control noxious weeds.

During construction of a new line, BCTC takes into account the potential for noxious weed or invasive plant introduction or spread as a result of construction activities. Contractors engaged in the project have mitigation measures in place, such as inspections and vehicle washing requirements, to avoid the spread of noxious weeds in the construction zone. BCTC will seed disturbed areas following construction to reduce the potential for noxious weeds. After the line is built, BCTC will work with the CSRD, RDEK, landowners and MOFR as noted above to deal with any noxious weed concerns.

Also please see BCTC’s response to Paul Bauman IR 1.3.
1.18 System planning report of BC Hydro.

The design criteria adopted caters for n-1 conditions within the substations but not for the transmission lines. What is the basis for selecting this criterion? Does it comply with WECC criteria? What measures will be taken in the design to enhance the availability of the transmission lines.

Voltage criteria.

Is this criteria applicable under light load system conditions, line energization and load rejection contingencies. The Glacier / Howser project required a 15 MVAr shunt reactor to control the 230kV voltage under these conditions, yet with a longer line from Invermere to Golden shunt reactors are apparently not required. There appears to be a conflict of design requirements. Design of the Invermere substation does not appear to cater for the possible construction of Glacier Howser project. Define the changes required in the substation design and transmission line R.O.Way in the event this project was to proceed.

Identify any additional land requirements to accommodate future development.

RESPONSE:

The basis for selecting the N-1 transmission planning criterion for those parts of the system in which it is applied is to provide the capacity, security and reliability required to meet the demands of the load and customers in the areas supplied by those parts of the system.

The criterion complies with WECC standards as well as NERC standards. The N-1 criterion is adopted for networked transmission systems but not necessarily for radial transmission systems. The NERC and WECC guidelines for radial transmission systems allow for the loss of service for load demand under N-1 contingency conditions (please refer to NERC/WECC Planning Standards, Section I “System Adequacy and Security”, Table I “Transmission System Standards – Normal and Contingency Conditions, Category B and Footnote b).

The measures that would be taken in the design of a transmission line to enhance its availability exceed the scope of the studies undertaken to-date for this project and will be determined during the design stage of the transmission line (please refer to Exhibit B-1, Appendix B, page 20, Section 3.3). Generally, any special design measures undertaken to enhance the reliability of a transmission line would depend on the nature of the hazards that the transmission line would be exposed to and could include reinforced structures where heavier loading conditions than normal are expected; reinforced footings and towers or the installation of protective concrete
barriers to protect against avalanches or landslides at locations where anticipated; and additional danger tree clearing outside of the right-of-way where this hazard may be encountered.

The voltage criterion indicated on page 22 of Exhibit B-1 (referred to in the question) is applicable under light load conditions. However, these are steady-state voltage criterion and do not apply to line energization and load rejection conditions during their short-term transient periods prior to the point in time at which system voltage control facilities and schemes restore the system to an acceptable steady-state operating voltage.

The published interconnection study prepared for Glacier/Howser in 2007 indicated that a 15 MVAr reactor is required at INV to prevent potential transient over-voltages caused by IPP generator rejection. This operating condition is not presently a factor in meeting the load supply requirements associated with the construction of a 230 kV transmission line from Invermere to Golden.

Consideration for the potential development of the Glacier/Howser IPP project exceeds the scope of the Columbia Valley Transmission Project studies and any changes required in the design of Invermere substation, to the transmission line right-of-way to accommodate this potential project, or both, would also exceed the scope of the studies. Further, any additional land requirements to accommodate the future development of the Glacier/Howser IPP project would exceed the scope of the studies required for the Columbia Valley Transmission Project as well. These issues will be addressed if and when the Glacier/Howser IPP reaches the point in its development that necessitates undertaking these studies.
1.19 Can you describe the land and ROW requirements for transmission lines that may be developed within the next 10 years and what lines may be required in the Columbia Valley? Does the Columbia Valley Transmission Project seek to be the best option for the requirements of the future of the Valley and reduce the extent of future power lines?

RESPONSE:

BCTC’s requirements for land, right-of-way and transmission lines presently anticipated within the next 10 years in the Columbia Valley are those associated with the Columbia Valley Transmission Project and described in the CPCN application for this project (Exhibit B-1).

The Columbia Valley Transmission Project as proposed in Exhibit B-1 has been identified as the best option to meet to meet the requirements of the Columbia Valley over the next 30 years.
1.20 Reference: IR 1 and IR 1A Responces 16 March 2010

1.20.1 If the need for power to Golden was identified back in the 1970’s why was this project not proposed one year, two years, or even five years earlier so that ample time was allowed for the best route be chosen on the basis of most cost efficient and energy efficient option instead of the only option that can be built in time to provide Golden adequate power?

RESPONSE:

The need for power supply to the Golden area identified back in the early 1970s was based on potential resource development (load growth). Long-term potential load growth in the order of 100 MVA to 200 MVA was forecast in the Golden area at that time and the feasible option to meet these requirements was the extension of the 230 kV system from Cranbrook. Long-range planning was subsequently initiated to meet these load supply requirements based on the staged development of a 230 kV system from Cranbrook to Invermere and then to Golden. That anticipated resource development did not materialize.

Until recently, the project could not be justified based on the annual load forecast provided by BC Hydro. Such forecasts are considered annually during BCTC’s ten year transmission capital planning process.

In 2006/2007, the load forecast provided by BC Hydro indicated that reinforcement of this system wouldn’t be required until after 2016/2017, i.e., beyond the ten year capital planning period and thus it was listed as a future project. In 2007/2008, however, the increase in the load forecast indicated that the Invermere to Golden load supply capability would be exceeded in 2012/2013. System planning studies were initiated at that time to resolve the system deficiency and in 2008/2009, the Columbia Valley Transmission Project was identified with a proposed in-service date of October 2012.

In regards to the Columbia Valley Transmission Project, time was available to undertake the studies necessary to evaluate a number of alternatives for upper Columbia Valley supply purposes. The preferred alternative has been identified and proposed as detailed in the CPCN Application.
1.20 Reference: IR 1 and IR 1A Responses 16 March 2010

1.1.1.1 “Planning for the extension of the 230 kv transmission facilities beyond Cranbrook was initiated as early as the 1970’s prior to the construction of INV. Growth projections at that time did support further expansion to Golden.”

1.20.2 Could the combination of L.P’s wood fired co-generation plant and perhaps a couple of large portable diesel or gas powered generators provide the additional power to provide time for the most cost efficient and energy efficient option to be built?

RESPONSE:

BCTC believes the best option which meets the needs of the upper Columbia Valley has been identified as the preferred option in its CPCN Application (Exhibit B-1). Exhibit B-1, Section 3.6, page 33 identifies possible interim measures to ensure adequate supply for an interim period, if necessary, prior to the CVT Project being built.
1.21 Reference: CPCN Application Binder 1, 22 Jan. 2010, System planning report, page 16, Section 3.1

“...historical load growth rate over the past twenty-three year period from Winter 1984/85 to Winter 2007/08 of 3.03%.”

1.21.1 Since 2008 and our large down turn of the economy and the almost complete halt of the building trade, the growth rate certainly must have been lower in 2009. What has caused this immediate need for more power in the Golden area in the very near future and in fact if there is a cause, why was it not identified in time to allow for the proper procedure to take place for the needed power line?

RESPONSE:

The load growth forecast contained in Exhibit B-1, Appendix C of Appendix B indicated that the load growth in the Golden area would exceed the supply capability of the existing Invermere to Golden 69 kV system by 2010/11. This load forecast was based on 2007/08 loads and a number of identified spot loads (developments) in the Golden Area over the forecast period which are expected to contribute to the overall load growth for the Golden Area. As indicated by the footnote on page 29 of Exhibit B-1, the peak load in 2008/09 in Golden was slightly above the 30 year forecast. Please also refer to BCTC’s response to Lake Windermere District Rod and Gun Club IR 1.2.

BCTC system planning procedure to address the identified needs in the area is described in BCTC’s response to Lake Windermere District Rod and Gun Club IR 1.20.1. The needs have been addressed in an appropriate and timely manner.
1.1 Precisely what measures will be taken to control invasive plant species both during and after construction activities? Will these be carried out in perpetuity? What measures will be taken should noxious species appear?

RESPONSE:

Please refer to BCTC’s responses to Lake Windermere Rod and Gun Club IR 1.17 and Paul Bauman IR 1.3.

Measures will be carried out in compliance with BCTC’s ongoing legal obligations.
1.2 Precisely what measures will be taken to control access by 4 X 4 vehicles and ATVs? How will use of new access be monitored?

RESPONSE:

BCTC will make use of existing access, where possible, during construction and maintenance of the transmission line. Please see Exhibit B-1, Section 5.2.1.4, page 57.

BCTC will cooperate with regulatory agencies in any effort they may make to manage public access over the CVT Project transmission right-of-way.

BCTC will not monitor use of access within the transmission right-of-way.
I presently have two water licenses from Barbour Lake. Well water in the area is of insufficient quality and quantity. The drainage of the proposed alignment is in the watershed of Barbour Lake. Will there be fungicides, herbicides, pesticides, toxic wood treatment, etc. used in the construction or maintenance of the right of way and transmission line? If so, which chemicals? As most such chemicals are considered toxic in groundwater in the low parts per billion, and as Barbour Lake has no surface water inlet or outlet (it is groundwater fed and drained), I consider this a critical issue. On the same concern, I would consider even small spills of gasoline, diesel, or other hydrocarbons to be a potential threat to our water source of Barbour Lake.

RESPONSE:

Barbour Lake is approximately 1 km to the south and west of, and uphill from, the proposed Toby Creek Diversion route. Construction and operation of the proposed transmission line should not affect the water quality or quantity in Barbour Lake.

In compliance with the BC Integrated Pest Management Act, BCTC has developed Pest Management Plans for

(a) Wood Structure Maintenance; and

(b) Control of Vegetation within Transmission Right-of-Way.

Copies of these plans are available on BCTC’s website at www.bctc.com.

Under the BCTC Pest Management Plan – Control of Vegetation within Transmission Right-of-Way, the following herbicides are approved for control of vegetation on the proposed transmission line:

(a) Glyphosate;

(b) Imazapyr;

(c) Chondostereum purpureum;

(d) Triclopyr;

(e) Aminopyralid; and

(f) Metsulfuron.
All herbicide used by BCTC and its agents and contractors to carry out vegetation management is required to adhere to these Pest Management Plans.

BCTC will develop a construction Environmental Management Plan, which will define measures to avoid, contain or, in the event of a spill, mitigate any effects of fluids such as gasoline, diesel, and hydraulic fluid during construction. BCTC has standard operation practices for managing spills during regular maintenance and operation of the transmission line.
1.4 Regarding the above questions, how will the above concerns be addressed should ownership of the line be transferred?

RESPONSE:

BC Hydro will own the transmission line and other assets to be constructed during the CVT Project. BCTC does not anticipate any change in ownership of these assets.
1.1 How far north is the Columbia Valley transmission line proposed to run?

**RESPONSE:**

The proposed 230 kV transmission line would start at Invermere substation and terminate at the proposed Kicking Horse substation west of Golden.
1.2 As you are likely aware there are IPP proponents north of Golden, near the Glacier Park boundary. If their projects were approved, who would be responsible for the payment of building the transmission line from the northern reaches of the Columbia Valley line, up to where the IPP’s would be?

RESPONSE:

Under BCTC’s Open Access Transmission Tariff, an IPP can only interconnect its generation facilities to an existing point of interconnection on the transmission system. The interconnection customer would be responsible for the costs of all facilities located between their generation facility and the point of interconnection to the BC Transmission system.

In the scenario described in this Information Request, the IPP would be responsible for the cost of the transmission line between its generation facility in the northern part of the Columbia Valley and the transmission system.