



Reference: AESO 2010 ISO Tariff Application, Section 4.5.1, Page 40, paragraph 185

Request:

- (a) Please confirm that the northwest Alberta transmission development used for this application was the Northwest Alberta Transmission Development Need Identification Document (herein referred to as "Northwest Development Plan") that was approved under U2006-205, U2006-275, U2007-348, U2008-318 and other approvals, if applicable.
- (b) Please confirm that the northwest Alberta area load is the same as NW9 in the Northwest Development Plan.
- (c) Please confirm that the Alberta portion of Rainbow area loads includes loads at the following substations:

| | | | |
|------|------|------|------|
| 747S | 748S | 779S | 791S |
| 795S | 797S | 828S | 850S |
| 786S | 832S | 890S | |

And that it excludes the following NW2 substations:

| | | |
|------|------|------|
| 788S | 853S | 855S |
|------|------|------|

Please update this list with any substation additions or changes to the Rainbow area load.

Response:

- (a) Confirmed. The approvals listed in the request were also listed in section 4.5.1 (page 40, paragraph 185) of the application.
- (b) Confirmed.
- (c) Confirmed.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1 to 4.5.3

Request:

- (a) Please provide a list of all of the applications for system access service (SAS) under rate FTS (or equivalent) that the AESO has received since 2006, including:
 - the date of the request;
 - the in-service date and MW level of the request ; and
 - the current status of the request.
- (b) Has the AESO connection process for SAS requests changed since BC Hydro made the requests listed in the response to IR BCH.AESO.01(a)? If so, what is the impact on each of these capacity increase requests?
- (c) Does the tariff prescribe a timeline for responding to service requests, or do the AESO's policies or procedures define such timelines?

Response:

- (a) BC Hydro has requested one increase in system access service under Rate FTS since 2006. The request was received on September 26, 2008, and was for an increase of 32 MW with an in-service date of January 15, 2012. The current status of the request is indicated in the table below, which is an excerpt from the AESO queue published on the AESO website and updated monthly. The status of a project is indicated under the new connection process by identifying the last gate completed. The BC Hydro request is indicated as having completed Gate 1 requirements on April 1, 2010, which means that the connection study scope has been determined and the stage 1 project data update package is complete. The current stage which follows Gate 1 includes completion of connection studies and preparation of a connection proposal.

| Project Number | Project Name | Planning Area | Generation(MW) | Load(MW) | Type | SASR ISD | Forecast ISD | SASR Date | Last Gate Completed | Last Gate Completion Date |
|----------------|--|---------------|----------------|----------|------|------------|--------------|------------|---------------------|---------------------------|
| 857 | BC Hydro Fort Nelson Load Increase from Rainbow Lake | 17 | 0 | 32 | Load | 2012-01-15 | 2012-01-15 | 2008-09-26 | 1 | 01-Apr-10 |

- (b) The AESO implemented a new connection process on April 1, 2010 for projects requesting to connect to the Alberta interconnected electric system. With respect to the BC Hydro load increase request, there will be no material impact as the AESO will complete the required studies for the project.

The project will be addressed in the new connection process, and will need to meet the requirements of each stage in order to proceed. Detailed process information is publicly available on the AESO website by following the path Customer Connections ► Connecting to the Grid.

- (c) The tariff does not prescribe a timeline for dealing with connection projects. Projects are addressed by the AESO based on several factors, including application date, available resources, policy or rule requirements, and any system dependencies.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1 to 4.5.3

Request:

Please provide a list of all of the SAS applications under rate DTS that market participants other than BC Hydro in the NW2 and NW9 areas have made and that the AESO has received since 2006 (please note, participant names are not required), including:

- the date of the request;
- the in-service date and MW level of the request; and
- the current status of the request.

Response:

The table below provides the requested information for all load system access service requests in the northwest planning area of Alberta, and is an excerpt from the AESO queue published on the AESO website and updated monthly. The current status of each project is indicated under the new connection process by identifying the last gate completed.

| Project Number | Project Name | Planning Area | Generation(MW) | Load(MW) | Type | SASR ISD | Forecast ISD | SASR Date | Last Gate Completed | Last Gate Completion Date |
|----------------|--|---------------|----------------|----------|------|------------|--------------|------------|---------------------|---------------------------|
| 857 | BC Hydro Fort Nelson Load Increase from Rainbow Lake | 17 | 0 | 32 | Load | 2012-01-15 | 2012-01-15 | 2008-09-26 | 1 | 01-Apr-10 |
| 892 | ATCO High Level 786S Transformer Upgrade | 18 | 0 | 14 | Load | 2010-12-31 | 2011-12-17 | 2008-11-25 | 2 | 01-Apr-10 |
| 1018 | ATCO Electric Manning New POD | 19 | 0 | 9 | Load | 2011-12-01 | 2011-12-01 | 2009-09-17 | 0 | 02-Oct-09 |
| 712 | ATCO Friedenstal 800S Transformer Addition | 20 | 0 | 10 | Load | 2009-10-31 | 2011-12-23 | 2007-07-25 | 1 | 01-Apr-10 |
| 924 | ATCO Electric Flyingshot Substation Upgrades | 21 | 0 | 52 | Load | 2010-04-15 | 2011-04-29 | 2009-04-27 | 2 | 01-Apr-10 |
| 925 | ATCO Electric Crystal Lake Substation Upgrades | 21 | 0 | 47 | Load | 2010-04-15 | 2011-03-22 | 2009-04-27 | 2 | 01-Apr-10 |
| 880 | ATCO Sturgeon 734S Transformer Upgrade | 23 | 0 | 16 | Load | 2011-02-01 | 2011-03-31 | 2008-11-18 | 2 | 01-Apr-10 |
| 1045 | ATCO Electric Edith Lake 739S Substation Upgrade | 26 | 0 | 32 | Load | 2011-10-01 | 2011-10-01 | 2009-11-05 | 1 | 01-Apr-10 |
| 1047 | ATCO Electric Swan River 735S Substation Upgrade | 26 | 0 | 15 | Load | 2011-10-01 | 2011-10-01 | 2009-11-09 | 1 | 01-Apr-10 |
| 853 | FortisAlberta Cold Creek Substation Upgrades | 29 | 0 | 22 | Load | 2010-10-01 | 2010-10-01 | 2008-09-10 | 3 | 01-Apr-10 |
| 874 | FortisAlberta Fickle Lake Substation | 29 | 0 | 7 | Load | 2010-12-01 | 2010-12-01 | 2008-10-30 | 2 | 01-Apr-10 |



Reference: AESO 2010 ISO Tariff Application, Section 4.5.1 to 4.5.3

Request:

Please provide a list of all of the SAS applications under rate STS that the AESO has received from BC Hydro since 2006 (please note, participant names are not required), including:

- the date of the request;
- the in-service date and MW level of the request; and
- the current status of the request

Response:

BC Hydro has requested one increase in system access service under Rate STS since 2006. The request was received on March 11, 2009, and was for an increase of 73 MW with an in-service date of November 30, 2011. The current status of the request is indicated in the table below, which is an excerpt from the AESO queue published on the AESO website and updated monthly. The status of a project is indicated under the new connection process by identifying the last gate completed. The BC Hydro request is indicated as having completed Gate 1 requirements on April 1, 2010, which means that the connection study scope has been determined and the stage 1 project data update package is complete. The current stage which follows Gate 1 includes completion of connection studies and preparation of a connection proposal.

| Project Number | Project Name | Planning Area | Generation(MW) | Load(MW) | Type | SASR ISD | Forecast ISD | SASR Date | Last Gate Completed | Last Gate Completion Date |
|----------------|--|---------------|----------------|----------|-------|------------|--------------|------------|---------------------|---------------------------|
| 915 | BC Hydro Fort Nelson Generating Station Upgrades | 17 | 73 | 0 | Other | 2011-11-30 | 2011-11-30 | 2009-03-11 | 1 | 01-Apr-10 |

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1 to 4.5.3

Request:

Please provide a list of all of the SAS applications under rate STS that market participants other than BC Hydro in the NW2 and NW9 area have made and that the AESO has received since 2006 (please note, participant names are not required), including:

- the date of the request;
- the in-service date and MW level of the request; and
- the current status of the request.

Response:

The table below provides the requested information for all generation system access service requests in the northwest planning area of Alberta, and is an excerpt from the AESO queue published on the AESO website and updated monthly. The current status of each project is indicated under the new connection process by identifying the last gate completed.

| Project Number | Project Name | Planning Area | Generation(MW) | Load(MW) | Type | SASR ISD | Forecast ISD | SASR Date | Last Gate Completed | Last Gate Completion Date |
|----------------|--|---------------|----------------|----------|-------|------------|--------------|------------|---------------------|---------------------------|
| 915 | BC Hydro Fort Nelson Generating Station Upgrades | 17 | 73 | 0 | Other | 2011-11-30 | 2011-11-30 | 2009-03-11 | 1 | 01-Apr-10 |
| 803 | Mustus Energy Biomass Generator | 18 | 30 | 0 | Other | 2009-07-02 | 2011-05-01 | 2008-03-11 | 2 | 01-Apr-10 |
| 1065 | Daishowa-Marubeni DMI-TG2 Steam Turbo Generator | 19 | 17 | 0 | Gas | 2011-06-01 | 2011-06-01 | 2010-01-14 | 0 | 11-Feb-10 |
| 816 | Weyerhaeuser Biomass Generation Project | 20 | 150 | 0 | Other | 2010-10-31 | 2011-03-01 | 2008-03-27 | 1 | 01-Apr-10 |
| 830 | Glacier Power Dunvegan Hydro Electric Project | 20 | 100 | 0 | Hydro | 2012-06-30 | 2012-07-01 | 2008-06-02 | 1 | 01-Apr-10 |
| 747 | Maxim Power Milner Unit 2 | 22 | 475 | | Coal | 2012-03-01 | | 2007-10-29 | 1 | 01-Apr-10 |
| 790 | Windlab Swan Hills Wind Project | 26 | 400 | | Wind | 2010-07-01 | 2999-12-31 | 2008-02-06 | 1 | 01-Apr-10 |
| 852 | Swan Hills Sagitawah Generating Facility | 26 | 344 | 0 | Gas | 2013-01-01 | 2013-01-01 | 2008-08-26 | 0 | 03-Sep-08 |
| 1054 | OTOKA Drayton Valley Biomass Plant | 30 | 23 | 2 | Other | 2012-03-30 | 2012-03-31 | 2009-12-07 | 0 | 10-Dec-09 |



Reference: AESO 2010 ISO Tariff Application, Section 4.5.1, Page 40, paragraph 185, 186 & 188, Northwest Alberta Transmission Development Need Identification Document – Volume I, Appendix H

Request:

- (a) Please confirm that planning studies in the Northwest Development Plan included loads of 30.8 MW and 34.5 MW for Fort Nelson for the winter peaks of 2009 and 2014 respectively. For reference, two load flow outputs from the Northwest Development Plan are attached which show the Fort Nelson substation in the upper left corner.
- (b) Please provide the load forecast for the Fort Nelson load that was used by the AESO in power system analysis (load flows, stability etc) for the Northwest Development Plan.

Response:

- (a) Confirmed
- (b) The forecast Fort Nelson load used in power system analysis for the northwest Alberta transmission development needs identification document were as follows:

| Year | Forecast Fort Nelson Load | |
|------|---------------------------|---------|
| | Winter | Summer |
| 2009 | 30 MW | 30 MW |
| 2014 | 34.5 MW | 33.8 MW |

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 45, paragraph 212

Preamble: The Application states: *“As well, the current Rate FTS and phase 1 of the northwest Alberta transmission development were approved at approximately the same time and under similar load conditions.”*

Request:

- (a) Does this statement reflect the relative comparability of the 30.8 MW and the 34.5 MW for 2009 and 2014 respectively with the BC Hydro forecast filed as an Undertaking (Exhibit 30-046b) in the AESO 2005/06 GTA (attached) where the Fort Nelson load is identified as 30.0 MW and 33.8 MW for those same respective years?
- (b) If not, what does the phrase “under similar load conditions” mean?

Response:

- (a-b) The statement was simply meant to reflect that the approvals of both the AESO’s 2005-2006 tariff application (in which the current Rate FTS was established) and the northwest Alberta transmission development needs identification document occurred less than a year apart.

Decision 2005-096, the initial decision on the AESO’s 2006 tariff application, was released on August 28, 2005, while Order U2005-464, which approved the AESO’s 2005-2006 GTA second refiling, was released on December 20, 2005. The first phase of the northwest Alberta transmission development was approved in Approval U2006-205, released on August 17, 2006. As the approvals were issued within a year of each other, the loads in the northwest Alberta region and the Rainbow area would have been about the same when both approvals were issued.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1, Page 40, paragraph 186

Request:

Please confirm that the 25 MW set out in paragraph 186 was the then-current FTS contract capacity amount for BC Hydro in Fort Nelson. If not confirmed, what was this number?

Response:

The contract capacity for BC Hydro at Fort Nelson was 24.5 MW until June 2007. The 25 MW was a rounded value representing that contract capacity.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1, Page 40, paragraph 186

Request:

- (a) Please provide the load forecast for the Alberta-based loads for the Rainbow area, for NW2 and for NW9 that was used in the Northwest Development Plan and any update since that time.
- (b) Please identify the portions of the load forecasts that are derived from DTS contract values and which are derived from forecast values.

Response:

- (a) The load forecast used for the northwest Alberta transmission development was prepared in 2005 and included the following forecast amounts:

Forecast 2005

| Area | BC Based Loads | Alberta Based Loads | Total NW2 | Total NW9 |
|------|----------------|---------------------|-----------|-----------|
| NW2 | 35 | 130 | 165 | — |
| NW9 | 32 | 1,278 | — | 1,310 |

The amounts were updated in each subsequent load forecast prepared by the AESO. The forecast prepared in 2009 included the following forecast amounts:

Forecast 2009

| Area | BC Based Loads | Alberta Based Loads | Total NW2 | Total NW9 |
|------|----------------|---------------------|-----------|-----------|
| NW2 | 110 | 111 | 221 | — |
| NW9 | 107 | 1,256 | — | 1,363 |

- (b) None of the Alberta loads were based on contract capacity amounts. The Alberta load forecast is an economic forecast as described in the Overview of the AESO's Future Demand and Energy Outlook included as Appendix C to the *AESO Long-Term Transmission System Plan*, provided as an attachment to information response AUC.AESO-021 (a).

The BC loads were based on a forecast provided to the AESO by BC Hydro.

Reference: AESO 2010 ISO Tariff Application

Request:

- (a) Please confirm that the load of 1310 MW identified in paragraph 208 is the load for the area identified as NW9. If not confirmed, what area(s) are included in the calculation of the 1310 MW?
- (b) Please provide the load forecasting methodology and practices used in the 2006 Northwest Development Plan and the methodology and practices that will be used in future plans.
- (c) For planning purposes, how does the AESO determine whether to use DTS contract load or forecast load?
- (d) Does the planning methodology differ depending on whether electricity is consumed in Alberta or the Fort Nelson area of BC? If so, what are the differences?
- (e) How was the 1310 MW baseline calculated for the Northwest Development Plan? Please list all assumptions that factored into the calculation.

Response:

- (a) Confirm, Please see information response BCH.AESO-009 (a) for additional information.
- (b) The load forecasting methodology which was used for the preparation of the 2006 northwest Alberta transmission development is essentially the same as the current methodology. The methodology is an economic forecast as described in the Overview of the AESO's Future Demand and Energy Outlook included as Appendix C to the *AESO Long-Term Transmission System Plan 2009*, provided as an attachment to information response AUC.AESO-021 (a).
- (c) For planning purposes the AESO primarily relies on the load forecast discussed in part (b) above, except where, based on the planner's experience and judgment, contract capacities need to be considered. For example, if a market participant had requested a large increase or decrease to contract capacity or had provided notice of termination for a specific large service, the contract capacity would be considered for planning purposes.
- (d) As discussed in information response AUC.AESO-003 (a), the AESO considers that it does not have obligations to forecast the needs or expand or enhance the transmission system to meet the needs of BC Hydro at Fort Nelson, whereas it does have those obligations with respect to Alberta. Although the planning methodology itself does not differ, the loads which are planned for accordingly reflect those different obligations of the AESO.

- (e) As discussed in part (b) above, the load forecast is an economic forecast. The assumptions are summarized in the Overview of the AESO's Future Demand and Energy Outlook included as Appendix C to the *AESO Long-Term Transmission System Plan 2009*, provided as an attachment to information response AUC.AESO-021 (a).

Reference: AESO System Access Service Agreement – Fort Nelson Demand Transmission Service, Issued February 12, 2008

Request:

- (a) What is the significance of the signed System Access Service Agreement contract level of 38.5 MW that the AESO has committed to for system access service at Fort Nelson?
- (b) How has this contract level been incorporated/considered in the development of rate FTS proposed in this application?

Response:

- (a) As stated in subsection 2(2) of section 2 of the proposed ISO tariff, “The ISO will provide such system access service up to the contract capacity of the market participant.” The AESO notes that system access service may be limited for reasons set out in the other subsections of that section of the tariff, and the AESO specifically ISO cannot and does not guarantee uninterrupted system access service in subsection 5(1).
- (b) As discussed in information response AUC.AESO-003 (a), the AESO considers it has an obligation to provide system access service to BC Hydro at Fort Nelson, but not to do so under the “postage stamp” provision of section 30(1) of the *Electric Utilities Act*. The current contract capacity was considered in the preparation of Rate FTS, but the AESO concluded the Fort Nelson capacity included in the northwest Alberta transmission development was a more appropriate basis for future charges under Rate FTS for the reasons set out in section 4.5 (pages 38-47) of the application.



Reference: AESO 2010 ISO Tariff Application

Request:

Please provide a ten-year history, by month, of:

- (a) Total Alberta Interconnected Electric System (AIES) coincident and non-coincident peak loads;
- (b) NW9 coincident and non-coincident peak loads, excluding Fort Nelson;
- (c) Rainbow area coincident and non-coincident peak loads, excluding Fort Nelson;
- (d) Fort Nelson coincident and non-coincident peak loads.

Response:

The AESO has provided the requested quantities by month from 2005 to 2009. Quantities for years prior to 2005 are not as readily accessible and are not as reliable as quantities from 2005 and later years.

- (a) Please see Attachment BCH.AESO-012 (a).
- (b) Please see Attachment BCH.AESO-012 (b).
- (c) Please see Attachment BCH.AESO-012 (c).
- (d) Please see Attachment BCH.AESO-012 (d).



Reference: AESO 2010 ISO Tariff Application

Request:

Please provide the AESO's current 5-year forecast, by month, of:

- (a) AIES coincident and non-coincident peak loads;
- (b) NW9 coincident and non-coincident peak loads, excluding Fort Nelson;
- (c) Rainbow area coincident and non-coincident peak loads, excluding Fort Nelson.

Response:

- (a) Please see Attachment BCH.AESO-013 (a).
- (b) Please see Attachment BCH.AESO-013 (b).
- (c) Please see Attachment BCH.AESO-013 (c).

Reference: AESO 2010 ISO Tariff Application Paragraph 216

Request:

- (a) Please provide the basis for the statement that the “need analysis” forecast a load of 25 MW for Fort Nelson.
- (b) Does the AESO consider the current Fort Nelson load in excess of 25 MW to be firm? Please explain.

Response:

- (a) As stated in section 4.5.1 (page 40, paragraphs 185-186) of the application, the northwest Alberta transmission development needs identification document (NID) was based on a need analysis that forecast a load of 1,310 MW in the northwest area in 2014-2015, including 25 MW of load in Fort Nelson. The NID was dated March 7, 2006, and included the following statements:

The AESO has tested the sensitivity of loss benefits in relation to changes in load in the Rainbow Lake area. Specifically, this includes the potential decline...of the Fort Nelson, BC load (25 MW). [page 38]

The Northwest regional total coincident peak load is approximately 1,142 MW and expected to grow to 1,310 MW by the year 2015. [page 57]

- (b) Yes, as discussed in information response BCH.AESO-011 (a), the AESO will provide system access service up to the contract capacity of BC Hydro at Fort Nelson. This is consistent with statements in the northwest Alberta transmission development NID, such as, “The AESO has assumed Fort Nelson as a firm load in its base analysis as it is obligated to serve Fort Nelson under the DTS contract with BC Hydro.” (pages 38-39)

Reference: AESO 2010 ISO Tariff Application Paragraph 185

Request:

- (a) Please provide the status of the system developments approved under U2006-205, U2006-275, U2007-348, U2008-318 and others if applicable, for Phase I of the Northwest Development Plan?
- (b) With the implementation for each of these improvements, what is the expected firm load that can be served in the Rainbow area and in Fort Nelson?
- (c) Recognizing that BC Hydro has a contract of 38.5 MW under rate FTS at Fort Nelson, does the AESO forecast a need for TMR with the implementation of Phase I as approved?
- (d) BC Hydro currently has an FTS contract at 38.5 MW with 10 MW of which are curtailable. At what point in the implementation of the Northwest Development Plan will this load become firm?
- (e) Have any new DTS contract loads been added to the system in the Rainbow area:
 - (i) Since BC Hydro's request for 38.5 MW was made?
 - (ii) Since BC Hydro's contract for 38.5 MW became effective?If so, are those new loads being served as firm load?
- (f) More generally, is there a queue for the allocation of available transmission capacity?
 - (i) If so, how does the queue work? I.e. is it based on SAS application date or the in-service date requested or something else? Please explain.
 - (ii) How does the above relate to the load forecast increases that may be provided by the distribution companies?

Response:

- (a) Please see Attachment BCH.AESO-015 (a) which is an extract for the northwest Alberta transmission development from the *Q4 2009 Transmission System Projects Quarterly Report* published on the AESO's website.

As well, part A of phase 1 of the northwest development was placed in service prior to Q4 2009 and is not included on the report. The components of part A include:

- reactive support in the Peace River/Grand Prairie region (7 sites); and
- installation of 240/144 kV transformer at Louise Creek 809S.

- (b) Based on studies completed for the northwest Alberta transmission development, once phase 1 of that development is complete in 2012, the Rainbow area transmission system will be able to support approximately 145 MW of load, including up to about 40 MW in

the Fort Nelson area, without the need for dispatch of TMR generation under normal conditions.

With dispatch of TMR generation, the AESO estimates that about 180 MW of load could be supported in the Rainbow area after phase 1 is complete. Additional operational studies will need to be completed to take into account the northwest Alberta transmission development, as well as load and generation changes since the previous studies were completed, to determine what additional load, if any, could be supported in Fort Nelson.

The AESO has not completed interim studies to determine incremental amounts of load that could be supported by the individual components of the northwest Alberta transmission development.

- (c) As discussed in part (b) above, based on previous operational studies, once phase 1 of the northwest Alberta transmission development is complete 2012, the Rainbow area transmission system is expected to be able to support approximately 145 MW of load without the need for dispatch of TMR generation under normal conditions. If Rainbow area load exceeds 145 MW then dispatch of TMR generation would be expected to continue to be required.
- (d) An automatic Under Voltage Load Shedding (UVLS) “safety net” scheme to maintain Rainbow area reliability following multiple contingencies had been designed and fully implemented in 2008 on the Alberta side of the transmission system in the Rainbow area. In December 2009, the AESO received confirmation that implementation of the UVLS scheme had also been completed on the Fort Nelson side of the Rainbow area. With implementation of automatic UVLS, required load will be shed automatically when multiple contingencies occur and lead to under voltage conditions.

The AESO will review Operating Policies and Procedures (OPP) 501 later this year with the expectation that the 10 MW curtailment provisions may now be removed, assuming no unanticipated issues arise.

The AESO notes that it considers the 10 MW curtailable load to be firm under the AESO’s tariff, as discussed in information response BCH.AESO-033 (d).

- (e) No additional Rate DTS contract capacity has been added in the Rainbow area since BC Hydro requested in December 2006 that its contract capacity be increased to 38.5 MW.
- (f) The AESO does not have a queue for transmission capacity, and in general there are no explicit rights to transmission capacity in Alberta. The AESO maintains a connection project queue as discussed in information response BCH.AESO-002.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.1, Page 40, paragraph 187

Request:

Regarding Transmission Must Run (TMR) costs in the Rainbow Lake area:

- (a) Please provide hourly TMR volume and cost provided by the Fort Nelson generator for the past three years.
- (b) Please provide the hourly TMR volume and cost provided by generators other than Fort Nelson in the Rainbow area for the past three years.
- (c) Please provide an estimate of the incremental costs that the AESO would have incurred for Rainbow Lake TMR if the Fort Nelson loads and generation were not interconnected in each of the past three years.

Please provide all details, assumptions and calculations in supporting Excel spreadsheets.

Response:

- (a-b) Please see Attachments BCH.AESO-016 (a-b)-A and -B which respectively provide TMR volumes and costs for the Rainbow area. The first attachment provides hourly TMR volumes for the Fort Nelson generator and for all Rainbow area generators in aggregate, excluding the Fort Nelson generator. The second attachment provides monthly TMR costs for all Rainbow area generators, including the Fort Nelson generator, in aggregate.

Hourly cost data for specific generators under TMR contract is information of a commercial and financial nature that is consistently treated as confidential by the AESO. The AESO considers that the provision of such detailed information over an extended period could result in harm to a market participant's competitive position by disclosing patterns and trends that could be used to advantage by a competitor, especially when services are procured under confidential bilateral contracts. The AESO therefore declines to provide the requested hourly cost information due to its confidentiality, in accordance with section 31(1)(c) of Commission Rule 001 on Rules of Practice.

- (c) The AESO estimates the range of potential impacts on the net cost of TMR supply for Alberta if the Fort Nelson load and generation had not existed from 2007 to 2009 would be from a \$5.5 million decrease in net cost to Alberta to a \$31.3 million increase in net cost to Alberta.

The AESO cautions that these estimates have a significant level of uncertainty as indicated by the range of potential impacts. Detailed operational studies are required to determine TMR requirements, taking into account load, generation, transmission system topography, and expected operating conditions. To obtain an accurate estimate of TMR requirements in the Rainbow area if the Fort Nelson load and generation had not

existed, comprehensive studies would need to be completed that would require significant time and resources. As well, it is not possible to determine whether other generation development would have occurred in the Rainbow area to supply ancillary services, or if the existing generation would have been upgraded or otherwise modified in response to the different market conditions.

However, the –\$5.5 million to +\$31.3 million range of economic impacts has been estimated based on the following simplifying assumptions:

- TMR volume requirements in the Rainbow area remain as defined in Operating Policies and Procedures (OPP) 501 with no change to reflect the removal of Fort Nelson load and generation; and
- no additional generation development and no upgrades or modifications to the existing generation occur in the Rainbow Area, and the unit prices of TMR contracts remain the same with the removal of Fort Nelson load and generation.

With these simplifying assumptions, the AESO estimated the lower economic impact by assuming the hourly TMR volume requirements associated with Alberta Rainbow area loads would be supplied by the same units as actually operated in Alberta in each hour of 2007-2009. Under this scenario, the cost of supplying TMR for Alberta Rainbow area loads increases but is more than offset by the reductions in TMR volumes previously required for Fort Nelson load.

The AESO estimated the higher economic impact by assuming the hourly TMR volume requirements associated with Alberta Rainbow area loads would require the dispatch of an additional existing generating unit, to at least its minimum operating level, to provide the same number of TMR units as actually operated in each hour of 2007-2009 (including the Fort Nelson generator). Under this scenario, the cost of supplying TMR for Alberta Rainbow area loads increases to a greater extent, such that the increase is no longer fully offset by the reductions in TMR volumes previously required for Fort Nelson load. However, the AESO considers it would be reasonable to assume additional generation development or upgrades or modifications to existing generation would have occurred in response to such an increased economic signal, or the higher TMR costs could have resulted in an earlier application by the AESO for the northwest Alberta transmission development.

As well, estimating historical impacts does not take into account the effects of the northwest Alberta transmission development in decreasing TMR requirements in the area, forecast changes in Fort Nelson and Rainbow area loads, and other factors that affect the volume and cost of TMR supply.

The calculations of the –\$5.5 million and +\$31.3 million endpoints of the range are provided in Attachment BCH.AESO-016 (c). As noted in part (a-b) above, the AESO considers the hourly TMR cost data upon which these estimates are based to be confidential information, and has therefore provided only the summary of the calculations by year.

Reference: AESO 2010 ISO Tariff Application

Request:

Please provide the AESO's forecast TMR requirements in the Rainbow area for 2010 to 2014 under the assumption that the Fort Nelson load is:

- (a) 25 MW
- (b) 38.5 MW
- (c) 50 MW
- (d) 75 MW (starting in 2012)

Please provide all details, assumptions and calculations in supporting Excel spreadsheets.

Response:

- (a-d) The amount of TMR generation that is required to meet reliability requirements in the Rainbow area is dependent on a number of factors including load, generation, transmission system topography, and expected operating conditions relevant to the area. The process of determining TMR requirements involves detailed operational studies that take into account expected load, generation, and transmission developments. TMR requirements are dependent on the total Rainbow area load and not just Fort Nelson load. The Rainbow area consists of Rainbow Lake (Area 17), High Level (Area 18), and Fort Nelson area in British Columbia.

Operating Policies and Procedures (OPP) 501 provides current TMR requirements in the Rainbow area based on the existing system configuration. In particular, Table 3 of OPP 501 provides the amount of TMR generation required as a function of Rainbow area load. Previous operational studies have indicated that the existing transmission system is not able to supply more than about 40 MW of load in the Fort Nelson area regardless of the amount of TMR generation dispatched due to system performance concerns.

For Fort Nelson area loads of less than 40 MW, OPP 501 (issued November 23, 2009) indicates the amounts of TMR generation that would be required. In January-March 2010, total Rainbow area load averaged about 98 MW, comprising about 73 MW for Alberta Rainbow area load and 25 MW for Fort Nelson area load. Assuming Alberta Rainbow area load of 73 MW, and assuming no additional factors need to be accounted for in determining the amount of TMR required:

- average Fort Nelson load of 25 MW (the current level) would require 90 MW of TMR generation from Rainbow area generators to supply total Rainbow area load of 98 MW; and

- average Fort Nelson load of 38.5 MW would require 110 MW of TMR generation from Rainbow area generators to supply total Rainbow area load of 111.5 MW.

As noted above, previous operational studies have indicated that Fort Nelson load above 40 MW cannot be supported on the existing transmission system. As well, the values mentioned above assume hourly loads at average levels, while actual TMR generation requirements would be determined on actual loads in each hour. At an average load of 38.5 MW, Fort Nelson load would be expected to exceed 40 MW in some hours, and as already discussed Fort Nelson load above 40 MW cannot be supported on the existing transmission system.

Based on the two Fort Nelson load levels mentioned above, on average 1 MW of additional Fort Nelson load requires about an additional 1.5 MW of TMR generation on the existing transmission system.

In the 2011-2012 period, the requirement for TMR generation in the Rainbow area is expected to be reduced by the northwest Alberta transmission development project currently underway. This project consists of several transmission additions and upgrades that will significantly strengthen the transmission system in the region. The in-service dates of the various components of the proposed development in the Rainbow area range from 2010 to 2012. It is anticipated that all of the proposed developments will be in place by the end of 2012.

Although utilization of TMR generation is expected to decrease following the completion of the proposed developments, the AESO notes that the northwest Alberta transmission development project did not contemplate the 50 MW and 75 MW load levels in the Fort Nelson area as raised in this information request. Additional operational studies will need to be completed to assess whether such load levels in Fort Nelson can be supported, or whether further transmission reinforcement or TMR service procurement would be required. As well, without completing additional operational studies, the AESO is unable to provide any specific estimates of the decrease in TMR requirements after the completion of the proposed developments, beyond the general expectation that TMR requirements will be lower after the proposed development than before for the same level of Fort Nelson load and assuming no other material changes affect TMR requirements in the area..

In the 2012-2014 period, TMR requirements in the area will also be affected by any incremental generation additions in the Fort Nelson area, any associated transmission upgrades, and any changes in Rainbow area load in Alberta. The amount of TMR that may be required in the Rainbow area on an interim basis will be determined as part of the planning and operational studies that will be performed for the connection process for the proposed load and generation additions.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46, paragraph 216 & 22

Request:

Please provide a working example calculation that includes calculations for at least a 20-year period of how the capital cost allocation to the proposed FTS rate applicable to BC Hydro would work for the following Development Cases under three separate Scenarios for each Development Case.

The base conditions are:

- BC Hydro requests, and receives, an FTS increase to a total of 75 MW of contracted FTS capacity on January 1, 2013; and
- Financial parameters would be those as are currently applicable for ATCO transmission projects; and
- The NW9 load in Alberta is the forecast underlying the AESO Long Term Transmission System Plan dated 2009 Appendix C Page 182, with identified peak loads of 1258 MW, 1391 MW and 1687 MW in 2013, 2018 and 2028 respectively.

Development Case 1:

The BC Hydro request results in a new capital expansion on the AESO NW system in NW9 of \$295 million (an AESO cost) and \$24 million on the B.C. side (a BCTC cost) (both in 2009 dollars), and provides a transmission capacity increase of 50 MW (from 1310 MW to 1360 MW). The request does not create any new material need for TMR.

Development Case 2:

The BC Hydro request results in a new capital expansion on the AESO NW system in NW9 of \$42 million (an AESO cost) and \$24 million on the B.C. side (a BCTC cost) (both in 2009 dollars), and provides a transmission capacity increase of 50 MW (from 1310 MW to 1360 MW). The request results in a need for 30 average MW of TMR for 1000 hours per year.

Development Case 3:

The BC Hydro request results in a new capital expansion on the AESO NW system in NW2 of \$295 million (an AESO cost) and \$24 million on the B.C. side (a BCTC cost) (both in 2009\$), and that does not provide any change to the 1310 MW of load that can be served in NW9. The request does not create any new material need for TMR.

Scenarios to be tested:

- Scenario 1: BCTC completes a transmission line in 2016, and as a result BC Hydro terminates its FTS contract effective January 1, 2017;
- Scenario 2: The BCTC line enters service in 2020, with the FTS contract terminated effective January 1, 2021; and
- Scenario 3: The FTS contract continues at 75 MW indefinitely.

In particular, for each Scenario under each Development Case:

- calculate the cost impact of this capital investment on the various scenarios under the proposed Rate FTS articles 3(3) and 7(1);
- show the proportion of the 50 MW expansion attributable to BC Hydro and to the AESO (if any), by year; and
- present the net capacity surplus/deficit position for the NW2 region, including BC Hydro load, that would exist if each of the scenarios were to unfold exactly as outlined.
- Show how contract and/or forecast loads in the calculations

Please provide an Excel spreadsheet of calculations and list all assumptions regarding all customer requests in the area.

Response:

Please see Attachments BCH.AESO-018-A through -I for the requested calculations of the capital cost allocations to BC Hydro at Fort Nelson, based on the development cases and scenarios provided in the request. The local system charges to BC Hydro, including applicable termination payments, are summarized in the following table:

| Case | Scenario 1 | Scenario 2 | Scenario 3 |
|------|---|--|---|
| 1 | 2010-2013: \$0.5 million/yr 2013-2016: \$11.9 million/yr 2017: \$274.0 million | 2010-2013: \$0.5 million/yr 2013-2016: \$2.1 million/yr 2017: \$42.1 million | 2010-2013: \$0.5 million/yr 2013-2016: \$11.9 million/yr 2017: \$274.0 million |
| 2 | 2010-2013: \$0.5 million/yr 2013-2020: \$11.9 million/yr 2021: \$201.0 million | 2010-2013: \$0.5 million/yr 2013-2020: \$2.1 million/yr 2021: \$31.0 million | 2010-2013: \$0.5 million/yr 2013-2020: \$11.9 million/yr 2021: \$201.0 million |
| 3 | 2010-2013: \$0.5 million/yr 2013-2034: \$11.9 million/yr 2035-2063: \$11.5 million/yr | 2010-2013: \$0.5 million/yr 2013-2034: \$2.1 million/yr 2035-2063: \geq \$1.7 million/yr | 2010-2013: \$0.5 million/yr 2013-2034: \$11.9 million/yr 2035-2063: \$11.5 million/yr |

As the AESO's most recent operational studies indicates it cannot serve more than 40 MW of load at Fort Nelson, the AESO assumes that the capital expansions in each of the development cases would allow it to serve the 75 MW proposed to be contracted in 2013.

As the analysis relates to the cost impact under subsections 3(3) and 7(1) of proposed Rate FTS, there is no effect related to changing TMR requirements. TMR charges to BC Hydro at Fort Nelson would be determined based on actual hourly TMR generation and cannot be estimated in advance based on the information provided.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46-47, paragraph 216, 217 & 220

Request:

If Scenarios 1 and 2 in BCH.AESO.18 occurred for Development Case 1, provide the calculation of the impact under Rate FTS section 7(1) of the existing ATCO Electric line, if any. Please explain the reason(s) for there being, or not being, any terminal payment, as the case may be, from BC Hydro to ATCO for that existing ATCO Electric line.

Response:

The impact of the existing ATCO Electric line is included in the analysis provided in information response BCH.AESO-019.

The current Rate FTS assumes the ATCO Electric line to Fort Nelson would continue to be used to provide service to Fort Nelson indefinitely, with costs recovered on a levelized basis over the years 2006 to 2034. The AESO proposes that if the Fort Nelson service is terminated prior to 2034, any remaining unpaid balance of those costs should be charged as an additional contribution under subsection 7(1) of Rate FTS.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 47, paragraph 220

Request:

If the above Scenarios 1 and 2 were to unfold for Development Case 1, and

- if the link from the BCTC system from Fort Nelson to Rainbow were to remain synchronous under normal operating conditions (resulting in a new synchronous interconnection between the BC Hydro interconnected system and the Alberta interconnected electric system); and
 - if that interconnection were to result in the equivalent of a 75 MW firm capacity benefit to the AESO NW9 region, ignoring all other benefits for simplicity,
- (a) Would the Alberta system be receiving, then or in the future, any residual value from having the original ATCO Electric line in service?
- (b) What would be the impact on the MW surplus/deficit positions calculated for Scenarios 1 and 2 for Development Case 1 in BCH.AESO-018?

Response:

- (a) If the hypothetical interconnection to the BCTC system provided a system benefit to the northwest Alberta region, there would be value from having the original ATCO Electric line in service. The assumption in information responses BCH.AESO-018 and -019 is that the original ATCO Electric line would serve no useful function after termination of the service to Fort Nelson, and the line could be removed from service and salvaged.
- (b) The AESO assumed that the forecast load in Alberta will be served in Scenarios 1 and 2 for Development Case 1 in information response BCH.AESO-018. Specific transmission system developments, if required to serve the forecast load, were not been included in the comparative analysis of the three development cases. It is therefore not possible to estimate the impact of providing system capacity through the hypothetical interconnection to the BCTC system rather than through other transmission system developments in Alberta.



Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46-47, paragraph 216, 219 & 220

Preamble: Paragraph 219 states the capital recovery for new lines would be about 40 years.

Request:

If Scenarios 1 and 2 in IR BCH.AESO.18 for Development Case 1 were to unfold, and if there would be a terminal payment required of BC Hydro to the AESO pursuant to Rate FTS article 7(1), describe (with specifics) any and all terminal rights that BC Hydro would receive or retain with respect to the transmission capacity associated with such terminal payment (i.e. the capacity that BC Hydro would have, under the proposed Rate FTS, paid for in full for the full 40 year life of the new asset).

Please provide all details, assumptions and calculations in supporting Excel spreadsheets.

Response:

The AESO assumes in information response BCH.AESO-018 that capital costs attributed to the service to Fort Nelson would serve no useful function after termination of the service. There would therefore be no “terminal rights” that BC Hydro would receive or retain after termination.

Reference: Application, para 556, Tariff s.15, subsection 3

Request:

If the Tariff were implemented as filed, and if either of Scenarios 1 and 2 for Development Case 1 in IR BCH.AESO-018 were to occur, then:

- (a) Is the referenced Section 15, subsection 3 a provision that BC Hydro and the AESO could use to immediately terminate BC Hydro's SAS service under rate FTS?
- (b) What conditions would the AESO require of BC Hydro for this to occur?

Response:

- (a) Yes, the AESO considers that the referenced section would allow termination by mutual agreement of the system access service agreement with BC Hydro at Fort Nelson.
- (b) The AESO assumes that, with immediate termination of the system access service to Fort Nelson, the capital expansion of \$295 million in Alberta would not occur. In that case, the AESO considers the primary condition on termination would be payment by BC Hydro of the remaining unpaid balance of the original ATCO Electric line providing service to Fort Nelson under subsection 7(1)(a) of proposed Rate FTS.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46, paragraph 216

Request:

Based on the application as filed, if additional transmission development was required to that included in the 2006 Northwest Development Plan, which development included new transmission and substation capital additions, and if such development would be triggered by a Fort Nelson load above 25 MW, but that the then current forecast load on the Alberta side of NW9 remained below 1285 MW for in excess of 10 years from the required in-service date based on the combined area need, then:

- (a) Please identify or describe the process that would be used to identify the available options to increase the transmission capacity?
- (b) What ability would BC Hydro have to influence the capacity upgrade selection being taken?
- (c) If there were both a wires solution and a non-wires solution (a solution based on the use of TMR) that were both technically sufficient, and if the non-wires solution were to have a lower overall NPV cost, what ability would BC Hydro have to influence the ultimate decision as between the wires and non-wires solution to increase the transmission capacity?
 - (i) Would the response to the previous question be different if the non-wires solution would be forecast to be required for a period of two years, as compared to a period of 5 years, as compared to a period of ten or more years? If so, how? If not, why not?
- (d) If a decision was made to complete the upgrade were made and approved, what certainty would BC Hydro have that such upgrade would be completed on time, and as approved?
- (e) If the Fort Nelson load above 25 MW combined with the Alberta load in NW9 does not exceed 1310 MW, however transmission and/or substation upgrades are required internal to NW9 (i.e. upgrades in the NW2 area) to support this combined load, does proposed FTS Rate 3(3)(b)(ii) apply?

Please provide all details, assumptions and calculations in supporting Excel spreadsheets.

Response:

- (a) The AESO evaluates various options for transmission system reinforcements involving transmission technologies, planning alternatives, power flows, reactive power, transient stability, land impacts, and economics, including various sensitivity analyses. Stakeholder consultation is also completed on geographic options, potential

technologies, and environmental and social considerations. All options must satisfy forecast capacity requirements as well as reliability criteria.

Options are then analyzed individually and in combination in consideration of a range of factors such as technical feasibility, cost, land-use impact, and flexibility to respond to future changes.

- (b) The AESO expects to exchange forecast information and work co-operatively with BC Hydro during the planning of any transmission system developments that would impact service to Fort Nelson, similar to the co-operation discussed in section 4.5.4 (page 45, paragraph 211) of the application. At a minimum, the AESO would expect BC Hydro to become engaged in the stakeholder consultation on the proposed development.
- (c) The transmission options may include TMR components. All options would be evaluated in the context of cost impacts related to TFO revenue requirement, losses, and TMR, which would include different durations of such costs, if applicable. All options would also be considered in the context of the factors listed in part (a) above as well as future flexibility, robustness, and sensitivity to changing conditions and capital at risk.

The AESO would expect to work co-operatively with BC Hydro, or at a minimum to engage BC Hydro in consultation, in evaluating the options for transmission system development.

- (d) The AESO and TFOs endeavour to complete projects in accordance with schedules developed during project planning. Project changes, procurement delays, unanticipated issues, contingencies, dependencies on other projects, and other factors may affect the actual completion of the project. The AESO expects that construction projects in Alberta would be subject to factors similar to those that affect BC Hydro's construction projects in BC.
- (e) Yes. Subsection 3(3)(b)(ii) of Rate FTS is based on the assumption that if Fort Nelson load does not exceed 25 MW and northwest Alberta area load does not exceed 1,285 MW, then no additional transmission system development would be needed in the northwest Alberta area. Conversely, if transmission system development is needed, it would be expected to be in response to either Fort Nelson load exceeding 25 MW or northwest Alberta area load exceeding 1,285 MW, even if the combined area load did not exceed 1,310 MW. The cost of the transmission system development would need to be recovered from market participants, and allocating the cost to Fort Nelson and Alberta in accordance with subsection 3(3)(b)(ii) would reflect the load growth that had caused the development.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46, paragraph 216

Request:

If BC Hydro's request for an increase in SAS under rate FTS to 75 MW in 2012 caused a need for a 40 MW increase in the NW9 transmission capacity (from 1310 MW to 1350 MW) and that was met with a wires solution (transmission or substation), and if independent of such increased requirement, the AESO had a forecast requirement within the Rainbow area of NW Alberta of greater than 40 MW of capacity starting in 2017 and continuing thereafter:

- (a) Could BC Hydro terminate its SAS service coincidentally (in 2017) with the need of the Alberta system, allowing the AESO to meet such new capacity for domestic load with the resources being freed up? (This case could occur, for example, if a BCTC line from the BCTC integrated system to Fort Nelson were completed by 2017.)
- (b) Would such a move trigger a payment from BC Hydro to the transmission provider (ATCO) pursuant to section 7(1) of the FTS? If so, specifically how would the payment be calculated, how would the tariff work, and what would the calculation look like? If not, how would the tariff work?

Please provide all details, assumptions and calculations in supporting Excel spreadsheets.

Response:

- (a) BC Hydro could terminate its system access service at any time pursuant to the provisions of Rate FTS and the terms and conditions of the ISO tariff in effect at the time of termination.
- (b) If the termination of BC Hydro's system access service resulted in transmission system benefits such as relief of regional transmission constraints, removal of capacity limitations which would restrict system access service to other market participants, or avoidance of future upgrades to the transmission system, such benefits would be recognized at the time of termination. Such recognition of transmission system benefits would be similar to the provision in subsection 5(6)(b) of section 9 of the proposed ISO tariff with respect to reductions or terminations of contract capacity for other system access services.

The specific treatment would be determined based on the details of the circumstances at the time. One possible approach would be similar to the adjustment of a market participant's construction contribution under subsection 4 of section 9 of the proposed ISO tariff. Under that approach, a revised allocation of costs to BC Hydro would be calculated as if the new circumstances had been known at the time of the original calculation. BC Hydro would then be responsible only for any unpaid difference between the original and revised calculations.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46, paragraph 216

Request:

If BC Hydro's request for an increase in SAS under rate FTS to 75 MW in 2012 caused a need for a 40 MW increase in the NW9 transmission capacity (from 1310 to 1350 MW) and that was met with a wires solution (transmission or substation), and if independent of such increased requirement, the AESO had a forecast requirement within NW Alberta of greater than 40 MW of capacity starting in 2017 and growing continuously thereafter, and in this case, BC Hydro's load requirement of 75 MW continues indefinitely at a constant 75 MW without increasing or decreasing:

- (a) Would BC Hydro's tariff obligation be for the cost of the 40 MW upgrade completed in 2012 (the 40 year amortization of the additional facilities plus any associated O&M) i.e. grandfathering in the cost of the 40 MW it caused; or
- (b) Would BC Hydro's tariff obligation be for the cost of the potentially growing list of assets that could be added through time to support any and all future needs that may be above the 1310 MW threshold (i.e. would the pool of assets in this case increase in 2017); or
- (c) Is it something else?
- (d) If the response is (a), is BC Hydro's liability for termination payment based on the one group of assets (i.e. the effect of the levelized cost for the approximately 40 year life that would end in approximately 2051)?
- (e) If the response is (b), and it is a growing list of assets to meet ever growing demand in the Alberta portion of the NW, but a continuous 75 MW FTS for Fort Nelson, would BC Hydro's liability be unbounded as new resources are built with ever extending end dates (i.e. extending beyond 2051) to their amortized lives?

Response:

- (a-c) The AESO proposes that, for the next northwest Alberta transmission development, the incremental annual revenue requirement be allocated between Fort Nelson and Alberta based on the respective Fort Nelson and northwest Alberta area load growth in each year. Please refer to the attachments to information response BCH.AESO-018 for example calculations.

As explained in section 4.5.4 (pages 46-47, paragraph 218) of the application, the AESO expects the Fort Nelson charge would be approved through an AESO application to the Commission, either as part of a tariff application or as an individual Rate FTS amendment. The AESO also expects that, as part of that process, new base loads would be established for Fort Nelson and for the northwest Alberta area above which load growth would be measured for the purpose of allocating costs of any further northwest

Alberta transmission developments. If the Fort Nelson load does not change from the 75 MW accommodated in the next northwest Alberta transmission development, no further costs would be attributed to the Fort Nelson service.

In summary, the AESO proposes that BC Hydro's tariff obligation for the next northwest Alberta transmission development be established at the time of that development and based on load growth forecast at that time. BC Hydro's tariff obligation for any subsequent northwest Alberta transmission development would be established in a similar manner at the time of that subsequent development and be based on load growth forecast at that time, above the load forecast used for the prior development.

This approach appears to be that described in part (a) of the request.

- (d-e) The AESO proposes that BC Hydro's termination payment be based on the one group of assets as described in part (a) of the request.

Reference: AESO 2010 ISO Tariff Application, Section 4.5.4, Page 46, paragraph 216

Request:

If BC Hydro's request for an increase to SAS service under rate FTS to 75 MW in 2012 caused a need for a 40 MW increase in the NW9 transmission capacity (from 1310 to 1350 MW), the upgrades were made to the system and the cost rolled through the FTS as envisioned in the proposed Rate FTS, and then subsequent to the addition being completed load (after 2014) in the Alberta portion of the Northwest region were to grow, what would be the impact on service to BC Hydro if:

- (a) Firm load curtailments were required on a regular basis because of lack of supply caused by a lack of new supply to meet the new (post 2014) load?
 - (i) In this case, would BC Hydro load be curtailed on a prorata basis with the Alberta load, or would there be some preferential treatment (to either BC Hydro or Alberta market participants)? Specify the AESO procedures that underpin this response.
- (b) Material amounts of TMR were required to support the new load (post 2014)?
- (c) Both of the above occurred?

Response:

- (a) The AESO is responsible for planning the Alberta transmission system so facilities are in place in a timely manner. The AESO generally does not plan the system with the expectation that firm load curtailments will be required on a regular basis.

However, in the event firm load curtailment is required, such curtailment would generally be implemented *pro rata* where practical and effective to do so, and only after all other steps to relieve the constraint have been implemented. The AESO's transmission constraint management consultation and rule development is on-going, and AESO procedures will be developed in accordance with the conclusion of that process and to accommodate the specific circumstances leading to firm load curtailment in the area.

The curtailment of the service would have no impact on the costs charged to BC Hydro under Rate FTS.

- (b) The AESO assumes that TMR generation would be dispatched to support the total Rainbow area load, consistent with the procedures followed today. The dispatch of TMR generation would therefore support the service received at Fort Nelson.

Similar to the approach discussed in information response BCH.AESO-025 (a-c), the AESO expects that, after the next northwest Alberta transmission development, new base loads would be established for Fort Nelson and for the Rainbow area above which

load growth would be measured for the purpose of allocating subsequent TMR costs. If the BC Hydro service did not grow beyond 75 MW, no subsequent TMR costs would be expected to be allocated to BC Hydro.

- (c) If both load curtailment and TMR generation were required, the impact would be the aggregate of the impacts discussed in parts (a) and (b) above.

Reference: AESO 2010 ISO Tariff Application Section 7: Proposed ISO Tariff – Rates, page 5 Section 3(3)(b)(ii)

Preamble: (3) (b) *a specific Fort Nelson rate based on:*
(ii) *if a future northwest Alberta transmission development is constructed, a levelized charge, determined using the applicable capital structure, return on equity, cost of debt and income tax rate, based on the cost of the future transmission development multiplied by the ratio of Fort Nelson forecast load in excess of 25 MW to the sum of Fort Nelson forecast load in excess of 25 MW and northwest Alberta area forecast load (excluding Fort Nelson load) in excess of 1285 MW, where the forecast loads are those provided in the needs identification document approved for the transmission development.*

Request:

- (a) Please confirm that the AESO allocates participant-related costs to market participants by contract capacity. If not, please explain how it is done.
- (b) If the AESO does confirm that participant-related cost recovery is allocated to market participants based on contract capacity, please explain why this methodology is not being applied in Fort Nelson.

Response:

- (a) Confirmed. Participant-related costs are shared between market participants based primarily on contract capacity and contract term under Article 9.10 of the AESO's current tariff. Participant-related costs will also be shared between market participants based on contract capacity under subsection 3 of section 9 of the proposed ISO tariff.
- (b) The capital cost proposed to be allocated to Fort Nelson is not a participant-related cost associated with a connection project, but is a local system cost related to the shared transmission system. The methodology for allocating participant-related costs is not applicable to allocating local system costs.

Reference: AEUB Decision 2005-096, p. 33; AESO 2010 ISO Tariff Application Section 7: Proposed ISO Tariff – Rates, page 5 Section 3(3)(b)(ii)

Preamble: In its Decision referenced above, the AEUB stated:

The Board has determined that the following should form the basis for charges to BCH for Fort Nelson services. DTS service charges should include the following:

1. *the postage stamp rate for bulk wires costs;*
2. *the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson;*
3. *the postage stamp rate for the AESO's own costs and other industry costs; and*
4. *the postage stamp rates for each of operating reserve charges, voltage control (TMR) and other system support charges.*

In the application, the AESO proposes:

- (3) (b) *a specific Fort Nelson rate based on:*
 - (ii) *if a future northwest Alberta transmission development is constructed, a levelized charge, determined using the applicable capital structure, return on equity, cost of debt and income tax rate, based on the cost of the future transmission development multiplied by the ratio of Fort Nelson forecast load in excess of 25 MW to the sum of Fort Nelson forecast load in excess of 25 MW and northwest Alberta area forecast load (excluding Fort Nelson load) in excess of 1285 MW, where the forecast loads are those provided in the needs identification document approved for the transmission development.*

Request:

Please confirm that capital costs related to bulk system upgrades are currently and will continue to be recovered at the postage stamp rate for SAS customers under rates DTS and FTS. If not, please describe how they are currently or will be recovered.

Response:

Confirmed. The proposed Rate FTS will continue to recover bulk system costs through the same postage stamp charge as Rate DTS.

Reference: AEUB Decision 2005-096, p. 33; AESO 2010 ISO Tariff Application Section 7: Proposed ISO Tariff – Rates, page 5 Section 3(3)(b)(ii)

Preamble: In its Decision referenced above, the AEUB stated:

The Board has determined that the following should form the basis for charges to BCH for Fort Nelson services. DTS service charges should include the following:

1. *the postage stamp rate for bulk wires costs;*
2. *the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson;*
3. *the postage stamp rate for the AESO's own costs and other industry costs; and*
4. *the postage stamp rates for each of operating reserve charges, voltage control (TMR) and other system support charges.*

In the application, the AESO proposes:

- (3) (b) *a specific Fort Nelson rate based on:*
- (ii) *if a future northwest Alberta transmission development is constructed, a levelized charge, determined using the applicable capital structure, return on equity, cost of debt and income tax rate, based on the cost of the future transmission development multiplied by the ratio of Fort Nelson forecast load in excess of 25 MW to the sum of Fort Nelson forecast load in excess of 25 MW and northwest Alberta area forecast load (excluding Fort Nelson load) in excess of 1285 MW, where the forecast loads are those provided in the needs identification document approved for the transmission development.*

Request:

Please explain how the AESO classifies costs as either “bulk” or “local”.

If upgrades in NW9 were to increase the transmission voltage from 144 kV to or above 240 kV, would the allocation of the associated costs change between bulk and local system costs?

If upgrades were caused in whole or in part by an increase in SAS under rate FTS, how would Section 3(3)(b)(ii) of Rate FTS be applied?

Please confirm how this is consistent with AEUB Decision 2005-096.

Response:

As discussed in section 4.3 (pages 28-32) of the application, transmission costs are functionalized as bulk system, local system, and point of delivery based on the results of three studies:

- the *Alberta Transmission Wires Only Cost Causation Study* filed in the AESO's 2005-2006 tariff application;
- the *2006 Transmission Cost Causation Update* filed in the AESO's 2007 tariff application; and
- the *Electric Transmission Operating and Maintenance Cost Study* filed in the current application.

The first two studies are provided as attachments to information response AUC.AESO-001, while the third study was provided as Appendix C to the application. The *Transmission Cost Causation Study* functionalized transmission costs as bulk system, local system, and point of delivery using three different methods, and ultimately averaged the results of the three methods to determine functionalization factors for use in the AESO's rate design. The *Transmission Cost Causation Update* provided additional refinements to the study, while the *Transmission O&M Cost Study* investigated non-capital costs in contrast to the capital costs investigated in the first two studies.

In the AESO's rate design, wires costs are functionalized as bulk system, local system, and point of delivery in accordance with the functionalization factors determined in the transmission cost studies and approved through AESO tariff application proceedings.

The transmission cost studies are not amended to reflect upgrades to individual transmission lines. Upgrades to multiple parts of the transmission system occur over time and, together with construction of new facilities, are considered in the comprehensive investigations that constitute the studies. The AESO expects that the studies will be updated periodically, and suggested in section 8.2 (pages 261-262) of the application that the *Transmission Cost Causation Study* may need to be updated in the AESO's next comprehensive tariff application.

A request for a system access service increase in capacity usually results in a connection project with costs classified as participant-related and system-related in accordance with subsection 3 of section 8 of the proposed ISO tariff. In the case of service under Rate FTS, the AESO would expect all connection project costs to be considered system-related, as the Fort Nelson service is not considered to include any point of delivery facilities. All costs would therefore likely be considered part of a system project and allocated between Fort Nelson and Alberta in accordance with the provisions of subsection 3(3)(b)(ii) of Rate FTS. The approach would be confirmed during development of the connection proposal to accommodate the increase in capacity.

Upgrades to accommodate an increase in a system access service would be expected to affect only the regional transmission system, the costs of which are considered to be recovered through the local system charge. It would be rare for an increase in system access service to affect the bulk transmission system. As the upgrade would be considered to be part of the local system, allocating its costs under subsection 3(3)(b)(ii) of Rate FTS and charging the greater of that cost or the Rate DTS local system charge appears entirely consistent with the determination of the Rate FTS local system charge in Decision 2005-096.

Reference: AEUB Decision 2005-096

Preamble: In Decision 2005-096 at page 32, the AEUB indicated, “The Board also believes that the rate charged for Fort Nelson service must be designed in such a manner that it will provide a fair and reasonable template that can be used in determining rates for other inter-provincial service provided by the AESO to other BC customers or by BCH to customers located in Alberta.

Request:

- (a) Please identify all inter-provincial services provided by the AESO.
- (b) Please identify all inter-provincial services that will be subject to the methodology for recovery of future TMR costs as proposed for Fort Nelson at Section 4.5.3.
- (c) Please identify all inter-provincial services that will be subject to the methodology for recovery of future capital costs as that proposed for Fort Nelson at Section 4.5.4.
- (d) To the extent that the AESO does not intend to apply the proposed Rate FTS methodology to other provincial loads, please provide the complete basis for deviating from the Board’s decision.

Response:

- (a-c) The AESO does not provide inter-provincial transmission service comparable to that provided to BC Hydro at Fort Nelson at any other location. For additional clarity, the AESO does not consider the export and import services provided over the Alberta-British Columbia and Alberta-Saskatchewan interties to be services comparable to that provided at Fort Nelson.
- (d) The AESO expects to use the proposed Rate FTS as the model for any future inter-provincial transmission services comparable to that provided to BC Hydro at Fort Nelson, consistent with the approach discussed in Decision 2005-096.

Reference: AESO 2010 ISO Tariff Application

Request:

Please provide other examples in North America where a regulator has approved incremental cost tariffs for one firm customer, while using postage stamp embedded cost rates for all other firm customers.

Response:

The AESO is not aware of an example where the specific scenario described has been approved. The AESO is also not aware of an example where a utility in one jurisdiction provides service to another jurisdiction and is restricted from recovering costs associated with providing that service, such that customers of the serving utility must subsidize service to the other jurisdiction.

Reference: AESO 2010 ISO Tariff Application

Request:

Please comment on the legality of the proposed incremental cost FTS tariff under the laws of Alberta, other provinces in Canada, and the U.S.

Response:

As discussed in information response AUC.AESO-003 (a), the AESO is not obliged to provide system access service to BC Hydro at Fort Nelson under the same “postage stamp” provisions required for service to Alberta market participants. However, the rate to be charged for the service that the AESO does provide to BC Hydro at Fort Nelson must be just and reasonable.

The proposed Rate FTS properly reflects the changing circumstances relevant to the provision of system access service to BC Hydro at Fort Nelson, based on a rate design that is fair, objective, and equitable.

Pursuant to its broad authority under Alberta's *Electric Utilities Act* in respect of matters concerning tariffs and rates, the Commission's approval of the proposed Rate FTS will mean that the rate is just and reasonable, not unduly discriminatory, and thus in accordance with Alberta law. Whether Rate FTS would be in accordance with the law of any other jurisdiction does not appear to the AESO to be relevant. That said, the position in British Columbia appears to be similar, as reflected in the British Columbia Utilities Commission's Decision (December 21, 2007) on BC Hydro's 2007 Rate Design Application, Phase II and III, which stated (page 46), “...the [BC Utilities] Commission may only act in accordance with the law, and the law is clear that rates are always just, reasonable and not unduly discriminatory when set in accordance with the Utilities Commission Act (except when they are interim).”

Reference: Table 5-12

Request:

- (a) Please provide an explanation and all supporting workpapers for the development of each billing determinant in this exhibit.
- (b) Please provide an updated analysis of the response to BCH.AESO-005 in the AESO's 2005-2006 GTA.
- (c) Does this table implicitly assume that Fort Nelson load exceeds 25 MW, but does not trigger the incremental cost provisions at subsections 3(3)(b)(ii), 3(5)(2), and 3(5)(3) of the proposed FTS tariff? If not, please explain any response fully.
- (d) Please comment on whether the interruptible/curtailable component of the Fort Nelson load is, or should be, treated differently than firm load for Bulk System, Local System and Other System Support charges.

Response:

- (a) The FTS billing capacity determinant was based on contract capacity and forecast peak metered demand provided to the AESO by BC Hydro, with ratchet levels based on billing history for the service.

The FTS coincident metered demand and metered energy determinants were forecast by using the load profile for the service for 2007-2008 in conjunction with the highest metered demand values.

Please see Attachment BCH.AESO-033 (a) for the monthly amounts which sum to the annual billing determinants.

For pool price, please refer to information request RDLE.AESO-001 (a).

- (b) Information response BCH.AESO-005 in the AESO's 2005-2006 tariff application proceeding provided information on wires costs, TMR expense, and a contribution towards fixed AIS costs proposed to be included in Rate FDS in that application.
 - (i) The AESO continues to use the levelized cost as calculated in that information response, as levelized costs are not generally revisited in subsequent tariff applications. The original calculation from the 2005-2006 tariff application proceeding is provided as Attachment BCH.AESO-033 (b).
 - (ii) The TMR expense calculation was provided in form only, with variables substituted for values that were considered commercially sensitive or confidential. The approach proposed by the AESO was not approved in

Rate FDS, and the AESO has proposed a different approach in this tariff application. As a result the AESO has not updated the TMR expense calculation.

- (iii) The contribution towards fixed AIS costs was not approved in Rate FDS, and the AESO has not updated that calculation.

- (c) The Rate FTS calculation in Table 5-12 assumes the provisions of subsections 3(3)(b)(ii), 3(5)(2), and 3(5)(3) of proposed Rate FTS do not apply because the conditions for those provisions are not forecast to be met in 2010.
 - The incremental local system charge provision in subsection 3(3)(b)(ii) of proposed Rate FTS applies only if a future northwest Alberta transmission development is constructed. No such development is included in the 2010 ISO tariff.
 - The incremental voltage control charge provision in subsection 3(5)(2) of proposed Rate FTS applies only when the AESO issues a dispatch to a fourth generating unit for TMR service in the Rainbow area, which is not expected to occur during 2010 as discussed in section 4.5.2 (pages 41-42) of the application.
 - The incremental voltage control charge provision in subsection 3(5)(3) of proposed Rate FTS applies only after completion of phase 1 of the northwest Alberta transmission development, which is not expected before 2012 and was therefore not forecast for 2010.

- (d) The AESO considers that the current curtailable component of the Fort Nelson load is not, and should not, be treated differently than other firm load for charges under Rate FTS. The AESO provides system access service up to the contract capacity of a market participant, and may limit, reduce, or interrupt that service under any applicable ISO rule or due to abnormal operating conditions

Reference: AESO 2010 ISO Tariff Application

Request:

To the extent that Fort Nelson is subject to incremental costing principles in the proposed FTS Sections 3(3)(b)(ii), 5(3), and 7, for load in excess of 25 MW as outlined at Sections 4.5.3 and 4.5.4, will Fort Nelson be exempt from transmission costs associated with load growth in other parts of Alberta which occurred after the Fort Nelson load reached 25 MW? Please explain your response and include details and assumptions.

Response:

As stated in the proposed Rate FTS rate sheet, and consistent with the structure of the currently-approved Rate FTS, the rate for the local system charge in Rate FTS will be the greater of:

- (a) the rate for the local system charge in Rate DTS; or
- (b) a specific Fort Nelson rate based on the levelized cost of the original ATCO Electric line providing service to Fort Nelson plus the levelized cost of future northwest Alberta transmission developments allocated to Fort Nelson.

If transmission costs associated with load growth in other parts of Alberta do not cause the local system charge in Rate DTS to exceed the specific Fort Nelson rate determined under proposed Rate FTS, Fort Nelson will be exempt from such costs. If circumstances result in the local system charge in Rate DTS exceeding the specific Fort Nelson rate, then the local system charge in Rate DTS would apply and Fort Nelson would be affected by local system costs incurred in other parts of Alberta.

Reference: AESO 2010 ISO Tariff Application Paragraph 199

Request:

At paragraph 199, the AESO expresses concern about the uncertainty regarding load growth in Fort Nelson:

- (a) Please contrast the proposed treatment of potential incremental load at Fort Nelson with incremental load in Alberta in transmission-constrained regions. For example, how would the AESO address a proposed incremental 50 MW Alberta load in the Fort McMurray area? Please explain your response.
- (b) Please explain why the procedure followed in response to part (a) would not be equally reasonable for Fort Nelson.

Response:

- (a) The reference at paragraph 199 expressed concern that, even though phase 1 of the northwest Alberta transmission development had been forecast to eliminate the requirement for TMR generation in the Rainbow area, significant load growth in Fort Nelson could again require TMR generation in the area. That concern led the AESO to propose an approach to allocate future TMR costs between Fort Nelson and Alberta, as discussed in section 4.5.3 (pages 42-44) of the application.

With respect to the incurrence of TMR costs, incremental load at Fort Nelson and incremental load in Fort McMurray would be treated similarly: Generation would be dispatched, if required, to provide TMR service to the area.

With respect to recovery of TMR costs, the AESO proposes that incremental costs be attributed to incremental load at Fort Nelson, while incremental costs in Fort McMurray would be recovered through the voltage control charge under Rate DTS which applies to load market participants throughout Alberta.

- (b) As discussed in information response AUC.AESO-003 (a), the AESO considers it has an obligation to provide system access service to BC Hydro at Fort Nelson, but not to do so under the “postage stamp” provision of section 30(1) of the *Electric Utilities Act*. Accordingly, and for the reasons discussed in section 4.5 (pages 38-47) of the application, the AESO has proposed that TMR costs be allocated to BC Hydro at Fort Nelson using an incremental approach.

Reference: AESO 2010 ISO Tariff Application

Request:

- (a) What are the AESO's plans for northwest Alberta beyond Phase 1 of the Northwest Development Plan?
- (b) Please provide the AESO's most recent evaluation of the costs and benefits of the next phase of a potential northwest Alberta plan.

Response:

- (a) Please see the discussion of transmission projects in the northwest region of Alberta included in section 8 (pages 356-361) of Appendix K to the *AESO Long-Term Transmission System Plan 2009* (provided as an attachment to information response AUC.AESO-021 (a)).
- (b) Please see the conceptual plans, including cost estimates, for the northwest region of Alberta included in section 8 (page 361) of Appendix K to the *AESO Long-Term Transmission System Plan 2009*. The specific solutions recommended for implementation will be identified in future needs identification documents. While engineering judgment was used in selecting the conceptual plans, they should not be interpreted as eliminating any other options or alternatives.

Reference: Proposed FTS tariff

Request:

- (a) Please confirm that the cost of any “future northwest Alberta transmission development” beyond that paid under the proposed Rate FTS will be recovered from all Alberta customers and not only those in northwest Alberta. If you cannot confirm, please explain.
- (b) Please confirm that TMR costs related to dispatching a fourth generating unit in the Rainbow Lake area that are not recovered from Rate FTS will be recovered from all Alberta customers, and not only those in the Rainbow Lake area. If you cannot confirm, please explain.
- (c) Will the AESO exclude the non-rate FTS customer costs for future northwest Alberta transmission development from the cost basis for the embedded cost bulk and local system FTS charges? Please explain your response.

Response:

- (a) Confirmed. Local system costs not recovered under Rate FTS will be recovered under Rate DTS. The local system charge under Rate DTS includes local transmission system costs from all regions of Alberta, and applies to load market participants throughout Alberta.
- (b) Confirmed. TMR costs not recovered under Rate FTS will be recovered under Rate DTS. The voltage control charge under Rate DTS includes TMR costs from all regions of Alberta, and applies to load market participants throughout Alberta.
- (c) The local system charge in proposed Rate FTS is the greater of the local system charge under Rate DTS or a specific Fort Nelson rate based on the levelized cost of facilities attributed to Fort Nelson.
 - If the Rate DTS local system charge is greater, the Rate FTS local system charge will include a *pro rata* share of all local transmission system costs recovered through the ISO tariff including those which would otherwise be attributed to Fort Nelson.
 - If the specific Fort Nelson rate is greater, the Rate FTS local system charge will include only costs attributed to Fort Nelson and will exclude other local transmission system costs recovered through the ISO tariff under Rate DTS.

Regional transmission developments such as those planned for northwest Alberta would generally not impact the bulk system charge. The Rate DTS bulk system charge includes all bulk transmission system costs recovered through the ISO tariff, and applies equally to proposed Rate FTS.

Reference: AEUB Decision 2006-096

Request:

In developing the proposed FTS incremental cost rate, please explain how the AESO factored in potential incremental benefits to the AESO from the expansion of FNG generating capacity.

Response:

With respect to the existing Fort Nelson generating capacity, the AESO considers that any potential benefits to Alberta are appropriately addressed by basing cost allocations on incremental growth above the load levels considered in the current northwest Alberta transmission development. This recognizes that prior developments in BC were made under prior tariff treatments.

With respect to future expansion of the Fort Nelson generating capacity, the AESO considers that such expansion should be decided on its own merit with a clear understanding of how future costs would be allocated to BC Hydro. This consideration prompted the proposed changes to Rate FTS included in the 2010 tariff application, even though additional costs are not expected to be allocated to BC Hydro until after 2014.

The AESO's tariff does not, and should not, specifically "factor in" potential benefits from associated generation when attributing costs to a load service. The legislation is clear: generation development is compensated through the sale of electric energy and ancillary services primarily in competitive markets, while costs of the transmission system, including costs of arranging provision of ancillary services, are to be paid by load customers.

Regardless of whether the Fort Nelson generation is expanded or not, or whether additional generation is developed in the Fort Nelson area or other alternatives to meet load growth in the Fort Nelson area are pursued by BC Hydro, significant load growth in Fort Nelson could give rise to significant additional costs in Alberta. Given that BC Hydro has several options for serving additional load in Fort Nelson and is not restricted to increasing system access service from Alberta, it is appropriate that BC Hydro be allocated incremental costs incurred in Alberta in providing additional system access service at Fort Nelson.

Irrespective of the considerations discussed above, the analysis provided in information response BCH.AESO-016 (c) indicates that there may be a net cost or a net benefit to Alberta from the existing Fort Nelson generation, depending on the specific assumptions made in the analysis. The AESO would expect that any similar analysis of the impact of future expansion of the Fort Nelson generating capacity would result in a similarly wide range from potential cost to potential benefit.