

Title: TMR Dispatch of a Fourth Generator

Reference: Application for Extension of AESO Interim Refundable Fort Nelson Rider H, December 29, 2008

Preamble: AESO stated that it “had anticipated that the load in the Rainbow Area would require transmission must-run (“TMR”) dispatch of a fourth Rainbow Area generator. Unanticipated load changes in the area have resulted in actual load being less than expected, such that no TMR dispatch of a fourth generator has been attributed to the increase in BC Hydro load, to the end of November 2008.”
p. 2

Request:

- (a) Provide a forecast of the expected use of AESO Interim Fort Nelson Rider H to the end of 2010.
- (b) With respect to AESO Interim Fort Nelson Rider H, what incremental TMR costs are expected to be incurred to the end of 2010, and what is the estimated impact on other AESO customers?

Response:

- (a) The unanticipated load changes referred to in the AESO’s application included:
 - the indefinite closure of the Footner Forest Products oriented strand board mill in High Level, Alberta announced by Ainsworth Lumber in late 2007;
 - the indefinite closure of the PolarBoard oriented strand board mill in Fort Nelson, BC announced by Canfor in mid-2008; and
 - the indefinite closure of the Tackama plywood plant in Fort Nelson, BC announced by Canfor in late 2008.

In addition, the temporary curtailment of the sawmill in High Level, Alberta was announced by Tolko Industries in February 2009.

Based on these closures and curtailment, the AESO forecasts Interim Fort Nelson Rider H to be used for 0 hours for 2009 through to the end of 2010.

The AESO notes that the closures and curtailment have been identified as indefinite or temporary rather than permanent. As a sensitivity test, the AESO also forecast use of Interim Rider H assuming the Canfor industrial loads in Fort Nelson return to service for the two-year period. With the Canfor loads in service, the AESO forecasts Interim Fort Nelson Rider H to be used for about 83 hours over the two-year period from 2009 through to the end of 2010.

- (b) Based on the closures and curtailment discussed in part (a) above, and the resulting use of Interim Rider H for 0 hours over 2009-2010, the AESO expects no incremental TMR costs to be incurred under Interim Rider H to the end of 2010. Accordingly, there would be no impact on other AESO customers due to Interim Rider H over that period.

The sensitivity test in part (a) above assumed the Canfor industrial loads in Fort Nelson returned to service, and resulted in use of Interim Rider H for about 83 hours over 2009-2010. Under those assumptions, the AESO forecasts about \$100,000 of incremental TMR costs to be incurred under Interim Rider H to the end of 2010. The incremental cost would be recovered 50% from BC Hydro and 50% from other AESO customers as an ancillary services cost through the AESO's Deferral Account Adjustment Rider C.

Title: Quantum of Rider H & Load Forecasts

Reference: Application page 2

Preamble: “Unanticipated load changes in the area have resulted in actual load being less than expected, such that no TMR dispatch of a fourth generator has been attributed to the increase in BC Hydro load, to the end of November 2008.”

Request:

- (a) Please provide a schedule that shows, by month from January 1, 2008 to January 31, 2009, the total TMR costs for the Rainbow area generators (as defined in OPP 501 under Note 3 to Table 3, i.e. “Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1”).
- (b) Please provide a schedule that shows, by month from January 1, 2008 to January 31, 2009, the total Rider H costs for the Rainbow Lake area and any amounts that were invoiced to BC Hydro under Rider H.
- (c) Please reconcile the response provided to HARVEST.AESO-003(a-e) in the Application 1554545 proceeding (attached) to the actual winter peaks in 2007/2008 and 2008/2009 and the 2007 and 2008 contracted capacity increases. Please explain fully any variances.
- (d) Please explain fully the “unanticipated load changes” and when they occurred.

Response:

- (a) The total TMR costs for the Rainbow Area generators, in aggregate by month, are provided below.

Month	Rainbow Area TMR Costs \$ 000 000
Jan 2008	\$2.89
Feb 2008	2.66
Mar 2008	2.82
Apr 2008	2.28
May 2008	3.32
Jun 2008	5.73
Jul 2008	4.29
Aug 2008	3.06
Sep 2008	2.93

Rainbow Area TMR Costs	
Month	\$ 000 000
Oct 2008	2.69
Nov 2008	2.50
Dec 2008	2.40
Jan 2009 (estimate)	2.52
Total	\$40.11

Note: Numbers may not add due to rounding

- (b) Please refer to Information Response UCA.AESO-007 (c).
- (c) (i) The cited information response included the following load forecast for the Fort Nelson area as provided by BC Hydro to the AESO. The AESO provides actual winter peaks for 2007-2008 and 2008-2009, with explanations for any variances.

Fort Nelson Area Forecast and Actual Load

Winter	Forecast (MW)	Actual (MW)	Variance (MW) and Explanation
2007-2008	28.5	35.3	6.8 Unanticipated new load in Fort Nelson area
2008-2009	29.3	34.1 to date	4.8 Unanticipated new load in Fort Nelson area
2009-2010	30.0		
2010-2011	30.8		
2011-2012	31.6		

- (ii) The cited information response included the following AESO forecast for Rainbow Area load which includes the Fort Nelson area. On reviewing the information in the response, the AESO determined that the definition of Rainbow Area load changed to include two additional substations in 2008-2009 and subsequent years. The AESO has therefore revised the forecast for 2007-2008 to also include those two substations, to provide better comparability of values. The AESO also provides actual winter peaks for 2007-2008 and 2008-2009, with explanations for any variances.

Rainbow Area Forecast and Actual Load

Winter	Forecast (MW)	Actual (MW)	Variance (MW) and Explanation
2007-2008 original	125.1	128.8	3.7 Unanticipated new load in Fort Nelson area
2007-2008 revised	141.0	144.7	3.7 Addition of substations 788S and 853S to definition of Rainbow Area
2008-2009	142.5	135.9 to date	-6.6 Unanticipated forestry plant closure in High Level
2009-2010	142.7		

Winter	Forecast (MW)	Actual (MW)	Variance (MW) and Explanation
2010-2011	143.6		
2011-2012	144.4		

(d) Please refer to Information Response AUC.AESO-001 (a).

Title: Supply Alternatives

Reference: Application page 2

Preamble: "The AESO has worked with BC Hydro during 2008 to develop reasonable alternatives to serve BC Hydro load in Fort Nelson."

Request:

- (a) Please provide a full explanation of the work that was undertaken with BC Hydro in 2008.
- (b) Please provide a list and fully describe the reasonable alternatives that were considered.
- (c) Please provide a copy of the "Fort Nelson Appendix N1" referenced in the application.
- (d) Please provide a listing showing the date, time and duration of each curtailment of Harvest's load under OPP 501 (Article 5.4.6) since Harvest was connected in March 2008 to January 31, 2009.
- (e) Please provide the AESO's position on the adequacy of the generation supply, including TMR capacity under contract, for the Rainbow Lake area. Please explain your response fully, including an evaluation of supply adequacy in light of the number and duration of curtailment directives to curtail Harvest's load under OPP 501.

Response:

- (a) The AESO's work with BC Hydro included the following:
 - (i) provision of information on and discussion of the elements included in the AESO's Northwest Alberta Transmission Development plan;
 - (ii) provision of information on and discussion of options that could potentially accommodate additional load in British Columbia;
 - (iii) exchange of forecast load information related to the Rainbow Lake and Fort Nelson areas;
 - (iv) review and discussion of options included in the Fort Nelson Appendix N1 to BC Hydro's *2008 Long Term Acquisition Plan*; and
 - (v) meetings, correspondence, and telephone calls related to the above topics and to operation of the transmission system in the Rainbow Area.

- (b) The AESO considers the most reasonable alternatives to serve BC Hydro load in Fort Nelson to be one or a combination of the options included in section 6 of the Fort Nelson Appendix N1 to BC Hydro's *2008 Long Term Acquisition Plan*, as summarized below:
- (i) upgrade the existing Fort Nelson generator's simple cycle gas turbine to a combined cycle gas turbine;
 - (ii) add a second combined cycle gas turbine generator of similar size to the existing Fort Nelson generator, either at the existing generator site or elsewhere in the area;
 - (iii) add a smaller combined cycle gas turbine generator, either at the existing generator site or elsewhere in the area;
 - (iv) develop or facilitate the development of other generation (biomass, hydro, wind, or geothermal) in the area;
 - (v) increase the transmission capacity from Alberta to Fort Nelson; and
 - (vi) interconnect Fort Nelson to the BCTC integrated transmission system.
- (c) Please see the attached Appendix N1 to BC Hydro's *2008 Long Term Acquisition Plan* (LTAP): 2008 Fort Nelson Resource Plan and Long-Term Acquisition Plan, as updated on October 24, 2008 and publicly available on the British Columbia Utilities Commission website at www.bcuc.com by following the path Current Applications ► BC Hydro - 2008 LTAP ► Exhibit B-1-10.
- (d) The AESO generally considers directives to individual customers to be confidential information which is not otherwise made publicly available. However, as the affected end-user has in this case requested the information, the AESO provides the date and time of each AESO System Controller directive to curtail new BC Hydro load under Operating Policies and Procedures (OPP) 501 (effective March 1, 2008) from March 2008 to January 2009. Given the dates and times, the operation of generators in the Rainbow Area can be determined from publicly-available information, and the AESO has therefore added descriptive information related to each directive.

No	Date	Issued	Ended	Description
1	Apr 11, 2008	08:08	13:32	Two units off-line
2	Jun 20, 2008	09:46	17:35	One unit off-line and TMR requirements in area not met
3	Sep 7, 2008	14:54	15:53	Two units off-line
4	Sep 15, 2008	11:20	21:08	Two units off-line
5	Sep 27, 2008	21:30	NA	Two units off-line; BCTC operator unable to contact load
6	Sep 28, 2008	07:06	10:16	Two units off-line
7	Oct 5, 2008	20:05	20:40	Two units off-line
8	Oct 6-7, 2008	22:44 Oct 6	05:25 Oct 7	Two units off-line
9	Oct 8, 2008	05:10	12:37	Two units off-line

No	Date	Issued	Ended	Description
10	Oct 23, 2008	17:36	20:02	TMR requirements in area not met
11	Nov 28, 2008	03:45	05:34	Two units off-line
12	Dec 19-20, 2008	20:14 Dec 19	00:12 Dec 20	TMR requirements in area not met
13	Jan 14, 2009	11:20	19:17	Two units off-line
14	Jan 15, 2009	13:21	15:27	Two units off-line
15	Jan 18, 2009	12:33	13:26	Two units off-line
16	Jan 18, 2009	13:55	19:56	Two units off-line
17	Jan 19, 2009	14:20	21:25	Two units off-line
18	Jan 19-20, 2009	22:11 Jan 19	00:22 Jan 20	Two units off-line
19	Jan 20, 2009	06:57	22:12	Two units off-line
20	Jan 21, 2009	05:28	15:14	Two units off-line
21	Jan 21-22, 2009	15:30 Jan 21	17:30 Jan 23	Two units off-line

- (e) The AESO has contracted four operational generators in the Rainbow Area to provide transmission must run (TMR) generation and to ensure adequacy of supply to meet local demand. Three local generators are required to be in-service at all times for Rainbow Area load up to 130 MW. The fourth generator has been contracted to serve as a back-up unit in the event one of the three generators is out of service. Furthermore, the Northwest Alberta Transmission Development project is in progress to improve area operation and minimize reliance on local generators in the long run.

For every hour from March 1, 2008 to January 31, 2009, three generators with a total output of up to 120 MW were sufficient to supply Rainbow Area load. However, due to planned and unplanned outages in the area the TMR requirements were sometimes not met. Harvest, as new BC Hydro load, was needed to be curtailed under OPP 501 due to the following causes:

- (i) One generator out of service due to planned maintenance and another generator on forced outage, usually referred to as N-2G (normal minus two generators) condition. Under N-2G conditions, the Rainbow Area cannot maintain minimum TMR requirements. Therefore, BC Hydro agreed to AESO requirements that new BC Hydro load (that is, Harvest) should be curtailed to support local voltage and in preparation for the next contingency event.
- (ii) To maintain Rainbow Area reliability following multiple contingencies such as N-2G conditions, an automatic Under Voltage Load Shedding (UVLS) "safety net" scheme has been designed and is being implemented at various nodes in the Rainbow Area. The UVLS settings are fully implemented on the Alberta side of the transmission system in the area, and the British Columbia Transmission Corporation (BCTC) has agreed to implement automatic UVLS at the Harvest Energy site as part of its interconnection with the AESO. However, the automatic UVLS at the Harvest Energy site is not yet implemented, and therefore the effectiveness of the safety net scheme is not ensured following multiple

contingencies in the area. To ensure reliable operation in the meantime, the Harvest load needed to be curtailed in preparation for the next contingency event when Rainbow Area TMR requirements were not met. After implementation of automatic UVLS, the load will be shed automatically when multiple contingencies occur and lead to under voltage conditions.

Title: Rainbow Lake Operation under Rider H

Reference: Application page 2

Preamble: "As well, at the time of filing its Interim Fort Nelson Rider H application, the AESO had anticipated that load in the Rainbow Area would require transmission must-run ("TMR") dispatch of a fourth Rainbow Area generator."

Request:

Please provide a spreadsheet that contains, by hour, the following information from January 1, 2008 to January 31, 2009:

- (i) The total Rainbow Area Load (as defined for Table 3 of OPP 501).
- (ii) The BC Hydro load (i.e. total load on 9L18 at the Alberta / BC boarder or the nearest measurement point(s)).
- (iii) The number of Rainbow Area Generators (as defined in OPP 501 under Note 3 to Table 3, i.e. "Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1") providing MW.
- (iv) The total output in MWh of all Rainbow Area Generators (as defined in OPP 501 under Note 3 to Table 3, i.e. "Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1").
- (v) The number of Rainbow Area Generators (as defined in OPP 501 under Note 3 to Table 3, i.e. "Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1") providing MW under TMR contract provisions.
- (vi) The total output in MWh of Rainbow Area Generators (as defined in OPP 501 under Note 3 to Table 3, i.e. "Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1") under TMR contract provisions.
- (vii) The number of Rainbow Area Generators (as defined in OPP 501 under Note 3 to Table 3, i.e. "Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1") providing MW under TMR contract provisions and attributable to Rider H.
- (viii) The total output in MWh of Rainbow Area Generators (as defined in OPP 501 under Note 3 to Table 3, i.e. "Rainbow area generators refer to FNG, RL1, RB5, RB2, RB3 and RB1") under TMR contract provisions and attributable to Rider H.

Response:

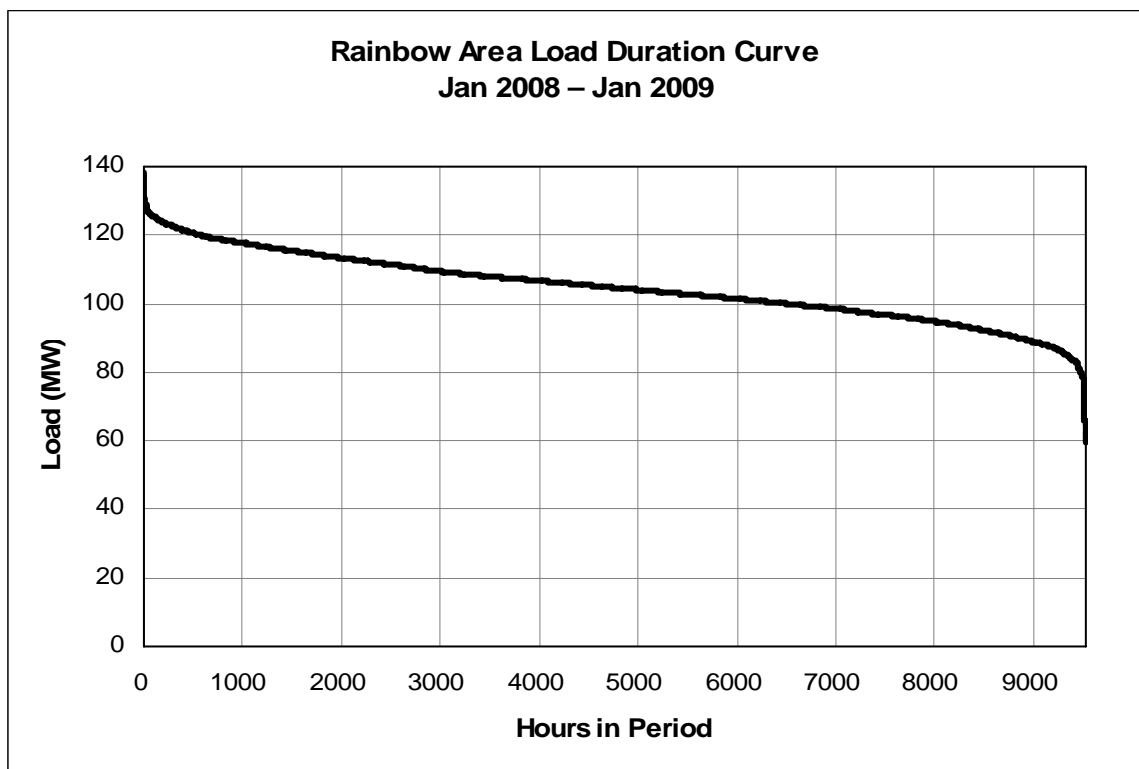
Much of the requested information is compiled by the AESO in the course of operating the interconnected electric system and is not otherwise available to the public for confidentiality and system security reasons. In particular, hourly output data for specific generators under TMR contract provisions is clearly 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 customer's competitive position by disclosing patterns and trends that could be used to advantage by a competitor. The AESO therefore declines to provide the requested information due to its confidentiality, in accordance with section 31(1)(c) of AUC Rule 001 Rules of Practice.

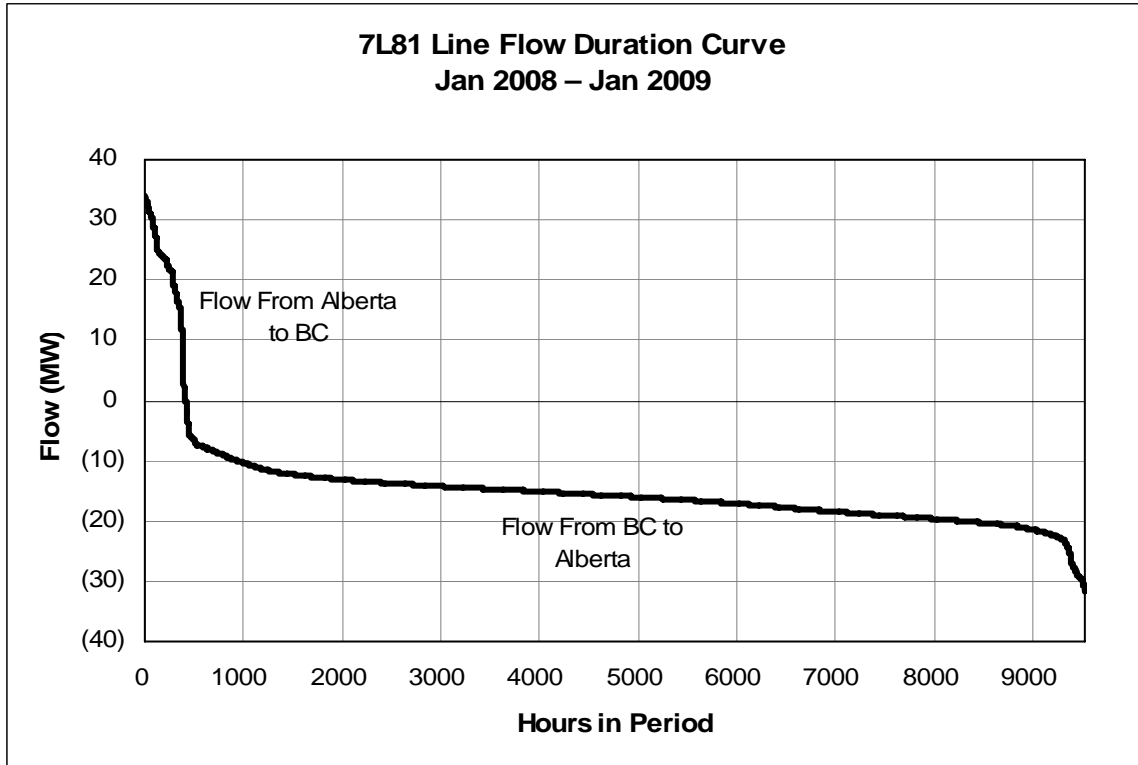
The AESO has considered each part of this information request, and, to be helpful, provides the following response which does not disclose information which is considered confidential.

All data used to create the graphs in this response is provided in Attachment HARVEST.AESO-003.

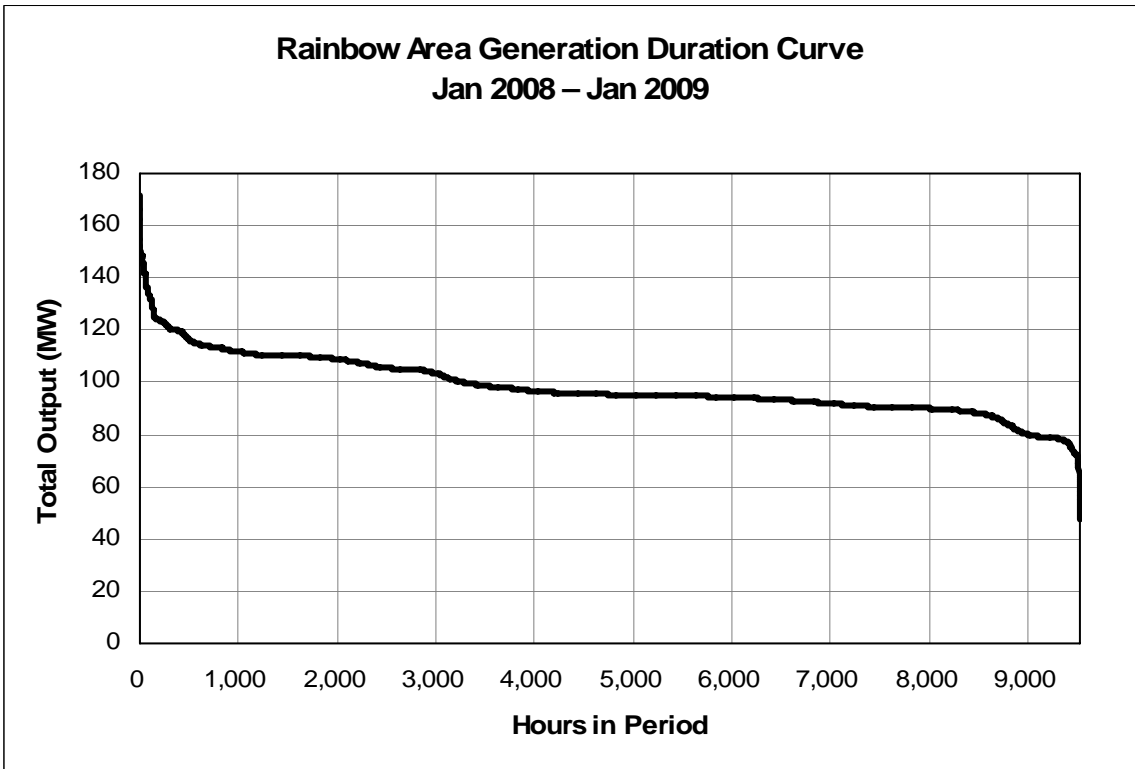
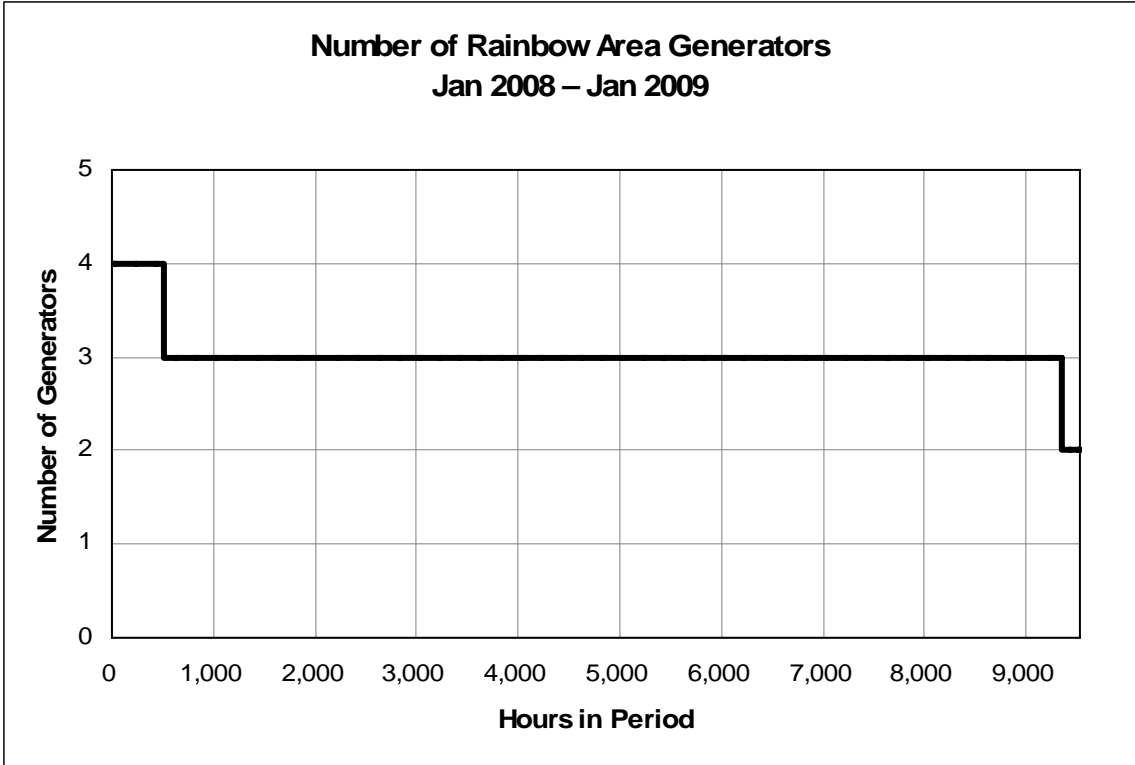
The AESO notes that data used to prepare this response originates from SCADA (Supervisory Control and Data Acquisition) rather than revenue metering. SCADA meter data is not of as high a quality as revenue meter data, and therefore some values may be inaccurate in some hours.

- (i-ii) Total Rainbow Area Load and the BC Hydro load are not generally available to the public on an hourly basis. However, the AESO provides the following duration curves for those loads for the requested period. As well, the line mentioned in part (ii) of the request is referred to as 7L81 in Alberta.





- (iii-iv) Generating unit output is available on reports on the AESO website, and the AESO therefore considers such information to be publicly available. Hourly information on the number and total output of the six Rainbow Area generating units is therefore provided in Attachment HARVEST.AESO-003. The following duration curves are also provided for additional information.



- (v-vi) Generation under TMR contract provisions is not available to the public, is of a commercial and financial nature, and is consistently treated as confidential by the AESO. The AESO therefore declines to provide the requested information due to its confidentiality, in accordance with section 31(1)(c) of AUC Rule 001 Rules of Practice. on an hourly basis.

- (vii-viii) There has been no TMR generation attributable to Interim Rider H from January 2008 through January 2009. Please refer to Information Responses AUC.AESO-001 (a-b) and UCA.AESO-007 (c) for additional information.

Title: Final rate

Reference: Application p. 2

Preamble: Taken from the original interim Rider H application, submitted December 19, 2007

“The AESO requests Rider H to be effective on an interim refundable basis from January 1, 2008, to December 31, 2008. In early 2008, the AESO and BC Hydro will cooperate to consider and study all reasonable alternatives to serve the incremental BC Hydro load. The AESO will then apply for a final rate determination on an effective and manageable alternative for service to BC Hydro in the Fort Nelson area in the latter half of 2008, allowing for its approval before the interim rider expires.”

Request:

- (a) Please describe whether the AESO will request a similar level of rates (50% sharing of incremental TMR costs) in the Final Rider H rate proposal as proposed in the interim rate application.
- (b) The AESO is requesting that Rider H will be in place for an approximately an additional 2 year period, please quantify the anticipated impact on customers over this period.

Response:

- (a) The AESO has not yet determined the approach it will propose for the final rate for service to Fort Nelson.
- (b) If the unanticipated load changes mentioned in the Interim Rider H Extension application continue, the AESO forecasts that Fort Nelson load will not require the dispatch of a fourth Rainbow Area generator through 2009 and 2010. Please refer to Information Response AUC.AESO-001 (a-b) for additional information.

The AESO considers any additional costs incurred through greater TMR dispatch volumes of three generators and attributable to Fort Nelson load to be offset by incremental revenue under Rate FTS for the increased load to BC Hydro, as discussed in the original Interim Rider H application.

The AESO therefore expects there to be no material impact on customers over the period when Interim Rider H would be in place.

Title: Calculation of the incremental TMR costs for Rider H

Reference: Electric Rates-Miscellaneous Order U2008-2, p. 3.

Preamble: Taken from the original interim Rider H application, submitted December 19, 2007

“With respect to the financial impacts of the proposed rider the AESO stated that it expected the final rate will be settled relatively promptly, potentially within 12 months of the interim rider becoming effective. If the rider is in place for 12 months, the AESO estimated the incremental TMR costs expected to be incurred is on the order of \$6.75 million. As BC Hydro will pay about 50% of these costs, the estimated impact on other AESO customers is estimated to be about \$3.4 million for approximately 12 months. The AESO considers this a reasonable amount, representing only about 0.5% of the AESO’s 2007 forecast DTS revenue requirement of \$644.9 million.”

Request:

- (a) Please provide calculations for AESO’s estimated incremental TMR cost of \$6.75 million per year.
- (b) Please confirm that the cost assumptions associated with the original Rider H application have not changed. If they have changed, please provide a new estimate.

Response:

- (a) The calculations of incremental TMR costs involve modeling of confidential information relating to TMR volumes and TMR contracts with specific generators. Such information is clearly of a commercial and financial nature that is consistently treated as confidential by the AESO. The AESO considers that the provision of such information could result in harm to a customer’s competitive position. The AESO therefore declines to provide the requested information due to its confidentiality, in accordance with section 31(1)(c) of AUC Rule 001 Rules of Practice.
- (b) The TMR contracts under which incremental TMR volumes would be required and calculated have not changed. The TMR volume forecasts have changed materially since the original Interim Rider H application, as discussed in Information Response AUC.AESO-001.

Title: AESO GTA application

Reference: Application, p. 2

Preamble: "...AESO currently expects to file its next GTA in the third quarter of 2009, with the expectation that the resulting rates will become effective about a year later, in the third quarter of 2010."

Request:

- (a) Please describe the consultation process the AESO is proposing to hold in regards to the next AESO GTA. Please outline the major activities, timelines, consultation events and the total length of the process.
- (b) Please contrast this proposed consultation process, with the AESO's last consultation process that was held for the 2007 tariff. Please outline the activities, consultation events, timelines and total length of the 2007 process.
- (c) Please describe the reasons why the AESO believes that the next AESO GTA process will be different (perhaps much shorter) than the previous process, whether it is expected to be more successful and if so, why.
- (d) Should the consultation process for the next GTA unfold over a similar timeframe as the 2007 process, please describe the impact on the Rider H application to BC Hydro and to Alberta transmission customers.

Response:

- (a) The AESO posted an invitation for stakeholders to become involved in consultation on its 2010 General Tariff Application (GTA) on February 5, 2009. That invitation included the following summary of planned consultation activities:
 - Feb 2009 – individual meetings with stakeholders who were active in the AESO's 2007 GTA
 - Mar-Apr 2009 – public consultation cycle: discussion paper, meeting, and comments
 - May-Jun 2009 – public consultation cycle: discussion paper, meeting, and comments
 - Q3 2009 – filing of application

The AESO also noted that it may be effective to develop working groups to address specific items in greater detail.

- (b) The proposed consultation process is generally consistent with that conducted for the AESO's 2007 GTA, although the previous process did not begin with individual stakeholder meetings. The 2007 GTA consultation was both more extensive and longer, consistent with the scope of proposals included in the 2007 GTA. The AESO's 2007

GTA consultation was summarized in section 3 of that application, which included the following:

Stakeholder consultation on Phase II matters was primarily conducted through the following streams from June 2005 through October 2006.

- Consultation on the AESO's 2005-2006 GTA Refiling from September through November 2005....
- Consultation on the development of the AESO's 2007 tariff, including the 2007 rates and 2007 terms and conditions of service, began in August 2005 and continued until October 2006....
- Consultation on export, import, and merchant interconnection tariffs from June through September 2005....

- (c) The AESO considers the scope of proposals that will be included in its 2010 GTA to be materially less than those included in its 2007 GTA. The 2007 GTA required responses to several outstanding directions and included two major studies, the *2006 Transmission Cost Causation Update* and the *Customer Contribution Policy Study*. As the AESO noted in its argument in the 2007 GTA proceeding, the consultation improved “the quality of its Application and provided significant opportunities for parties to understand one another’s concerns and proposals prior to engaging in the Board’s formal review process” (page 4).

The AESO expects the consultation for its 2010 GTA to similarly improve its application and aid parties’ understanding of its proposals.

- (d) As explained in Information Response UCA.AESO-001 (b), the AESO expects there to be no material impact on customers over the period when Interim Rider H would be in place.

Title: Work with BC Hydro

Reference: Application, p. 2

Preamble: “The AESO has worked with BC Hydro during 2008.....the AESO has concluded it should more fully develop its long term transmission plan.....before filing a final rate application.”

Request:

- (a) Please describe if any or all of the “work” with BC Hydro is considered confidential? If so, please provide all such reasons.
- (b) Please describe the consultation activities that AESO will undertake in regards to more fully developing its long term transmission plan for the Rainbow Area. Please indicate if these consultation activities will be open to participation of the UCA and other Consumer groups. If not, please fully explain.
- (c) Please provide all the reasons why the long term transmission plan is required before the AESO creates a permanent rate for the incremental load at Fort Nelson. Please include in the discussion:
 - (i) When this long term plan will be ready;
 - (ii) A contrast of the merits and disadvantages of waiting for the long term plan before proceeding to a final rate; and
 - (iii) Please describe any and all other types of analysis that the AESO feels necessary to prepare prior to finalizing the final rate application.

Response:

- (a) Any discussions or correspondence with BC Hydro which included information specific to individual customers would generally be considered confidential. As well, preliminary or speculative information or proposals would generally not be disclosed until a more thorough review and assessment had been completed.
- (b) Consultation will be consistent with that conducted for other recent transmission system planning projects, and will offer all stakeholders an opportunity for meaningful input on the project. Specific consultation activities have not yet been identified for the long term transmission plan for the Rainbow Area.
- (c) The AESO considers it important to more fully develop its long term transmission plan for the Rainbow Area before filing a final rate proposal to ensure that the rate proposal

will appropriately accommodate probably future costs. As noted in the original Interim Rider H application (page 2):

In the AESO's view, [the current Rate FTS] was based on costs consistent with a forecast contract capacity of 24.5 MW, and does not necessarily apply in perpetuity regardless of changing circumstances in the area. In BC Hydro's view, the AESO is required to provide service under the current tariff and cannot charge BC Hydro more than the "postage stamp rate" for operating reserve charges, voltage control (TMR), and other system support charges as set out in Decision 2005-096.

This difference of views illustrates the importance of examining future circumstances before filing a final rate proposal.

At this time the AESO has not determined when the long term transmission plan will be finalized. However, proposing a final rate prematurely could potentially lead to further differences of views and possibly complaints to the AUC, if the final rate does not appropriately accommodate changes to the transmission system. The AESO must also ensure its final rate proposal is consistent with legislation and regulatory precedent, is just and reasonable, and will appropriately reflect prudent costs reasonably attributable to providing service to Fort Nelson. Finally, the AESO considers it reasonable to allow other stakeholders an opportunity to comment on the final rate proposal as part of its 2010 GTA consultation process.

Title: Northwest Transmission

Reference: Application, p. 2

Preamble: Fort Nelson load is anticipated to grow substantially, and may be potentially resourced from Alberta. The UCA's understanding of the intent of the Northwest Alberta Transmission Development was to eliminate TMR in the region.

Request:

- (a) Please confirm that one of the goals of the above referenced approved Need application (over \$300 Million of committed capital), was to eliminate the use of TMR in the Rainbow Lake/ Fort Nelson region.
- (b) Please describe the load level from BC Hydro that was included in the NW Need application.
- (c) Please comment on the potential that BC Hydro may request additional supply in the Northwest region that may require the ongoing use of TMR. Should this occur, please comment on the likely success of the Northwest Development Need application?

Response:

- (a) Confirmed. As noted on page 22 of Volume I of the AESO's *Northwest Alberta Transmission Development Need Identification Document* dated March 7, 2006, "The proposed development also eliminates the use of TMR from the Rainbow Lake area."
- (b) Fort Nelson was assumed to be a 25 MW firm load in the base analysis in the AESO's *Northwest Alberta Transmission Development Need Identification Document* dated March 7, 2006, as noted on page 38 of Volume I.
- (c) BC Hydro may request additional supply, just as customers in Alberta may also request increases in their load services in northwest Alberta. The AESO will assess requests for such increases and develop appropriate plans to supply them. The plans may include use of TMR in the Rainbow Area or additional development of the northwest transmission system. With respect to BC Hydro, supply alternatives exist that do not require the ongoing use of TMR or transmission development in Alberta, as summarized in Information Response HARVEST.AESO-002 (b).

The AESO considers the success of the *Northwest Alberta Transmission Development Need Identification Document* to be demonstrated by the Alberta Energy and Utilities Board's issuance of Approval U2006-275 on October 27, 2006.

Title: Long Term Acquisition Plan – BC Hydro

Reference: Application, p.2

Preamble: “BC Hydro has also discussed the alternatives in the Fort Nelson Appendix N1 to its 2008 Long Term Acquisition Plan filed with the British Columbia Utilities Commission on June 12, 2008 and updated on October 24, 2008.”

Request:

- (a) Please provide a complete copy of this above referenced Acquisition Plan?
- (b) From this Acquisition Plan:
 - (i) Please summarize the load growth scenarios that are expected by BC Hydro in the Fort Nelson region over the next 10 year period?
 - (ii) Please outline and summarize the potential longer term supply options from Alberta that are being considered by BC Hydro?
- (c) Please comment on the following:
 - (i) The Fort Nelson region will likely require additional electricity supply over the next 10 year period due to strong load growth. One supply option involves requesting over 70 MW's of generation from Alberta – that will likely require Alberta to run TMR to supply this load; and
 - (ii) Should the scenario outlined in (c) 1. above unfold for BC Hydro, please comment on the importance of the Fort Nelson rate application to the AESO's DTS customers?

Response:

- (a) Please refer to Information Response HARVEST.AESO-002 (c). If parts of BC Hydro's *2008 Long Term Acquisition Plan* (LTAP) are required beyond Appendix N1, they are publicly available on the British Columbia Utilities Commission website at www.bcuc.com by following the path Current Applications ► BC Hydro - 2008 LTAP.
- (b)
 - (i) The electric supply and relevant market forecasts are extensively detailed by BC Hydro in section 5 (pages 21-37) of Appendix N1 of BC Hydro's 2008 LTAP.
 - (ii) Please refer to Information Response HARVEST.AESO-002 (b). Additional detail is provided in section 6 (pages 37-53) of Appendix N1 of BC Hydro's 2008 LTAP.

- (c) (i) The scenario described in the request is included in the alternatives discussed in section 6 of Appendix N1 of BC Hydro's 2008 LTAP.
- (ii) Regardless of how the AESO's service to BC Hydro at Fort Nelson evolves in the future, the AESO considers it important to develop a rate proposal that appropriately accommodates that service. The greater the costs attributable to the service, the larger the potential impact on rates paid by other AESO customers.

Title: Unanticipated load changes

Reference: Application, p. 2

Preamble: “Unanticipated load changes in the area have resulted in actual load being less than expected, such that no TMR dispatch of a fourth generator has been attributed to the increase in BC Hydro load, to the end of November, 2008.”

Request:

- (a) Given that load in the Fort Nelson region has declined, please provide all reasons why the Rider H application is still required?
- (b) Please clarify the AESO's expectations in regards to usage and cost of Rider H by BC Hydro over the next two to three year period (2009 – 2011)? Is usage expected to be less than described in the initial application, given that actual load is less than expected?
- (c) Please update the information contained in the extension application in regards to the usage of Rider H for December, 2008 and as many days as possible in January, 2009.

Response:

- (a) The unanticipated load changes in the area have been identified as indefinite or temporary rather than permanent, as discussed in Information Response AUC.AESO-001 (a). It is therefore possible that load may return in the future such that charges under Interim Rider H could apply.
- (b) Please refer to Information Response AUC.AESO-001 (a-b).
- (c) There has been no TMR dispatch of a fourth generator attributed to the increase in BC Hydro load, to the end of January 2009. There have accordingly been no charges to BC Hydro under Interim Rider H to the end of January 2009.

Title: Rate impact

Reference: Application, p. 2

Preamble: "...Rider H to have no undue impacts on other AESO customers ..."

Request:

- (a) Please clarify the AESO's intention with an interim refundable rate? For example, would the AESO agree that it is possible that upon application of the final Rider H rate, the Commission may decide that BC Hydro should be charged 100% of all incremental TMR costs associated with the 10 MW of Rider H load?
- (b) Should the Commission decide that BC Hydro should be charged 100% of all incremental TMR, can the AESO offer its opinion if this level of rate increase (50% of TMR costs for 2.5 year period) should or should not be classified as "rate shock" (an argument previously presented by BC Hydro in regards to the Fort Nelson rate).
- (c) In the original application, the AESO outlined that Alberta customers would be expected to fund \$3.4 million per year to support this incremental request. Please clarify the AESO standards when assessing impacts on customers in regards to the preamble reference of "no undue impact". Why is \$3.4 Million per year not considered an undue impact?
- (d) Would the AESO agree that a customer that pays only 50% of the costs that a customer directly creates goes against the rate principle of cost causation? Please provide all reasons for your response.

Response:

- (a) The AESO provided the following explanation in its original Interim Rider H application:

Both [the AESO and BC Hydro] agree that the approval of an interim refundable rider will accommodate the immediate need for service, allowing issues to be appropriately determined and resolved before the [AUC] at a future date. (page 2)

When a final rate for service to BC Hydro is approved, either the AESO or BC Hydro will pay to the other party the difference between costs recovered under the interim rider and costs that would have been charged under the final rate. (page 5)

The AESO agrees that the final rate may charge 100% of all incremental TMR costs to BC Hydro, may also charge less or other costs, and will reflect the determination of the AUC on the matter.

- (b) If the AUC determines that 100% of all incremental TMR costs should be charged to BC Hydro, the AESO assumes such costs would not constitute “rate shock” as the AUC typically includes such considerations in its decisions.
- (c) The AESO assesses impacts of rate changes on customers based on the specific circumstances of each case, and typically considers the magnitude of the impact, its probability, the number of customers affected, the duration of the impact, rate stability, intergenerational equity, the resulting price signals, and other factors. The original application explained on page 5 that Interim Rider H would have no undue financial impact on other AESO customers for the following reasons:
- The costs represented “only about 0.5% of the AESO’s 2007 forecast DTS revenue requirement of \$644.9 million.”
 - Interim Rider H would be in place for a limited period of time.
 - Charges under Interim Rider H would be interim and final charges would be resolved before the AUC at a later date.
 - The costs incurred would be similar to those that would be expected if an Alberta customer in the Rainbow Area were to request a similar increase in load.
- (d) Under the AESO’s approved DTS rate, TMR costs are recovered from all customers through a fixed \$/MWh charge and are not assessed against individual customers or even customers in a specific region. The FTS rate is based on the DTS rate and, in particular, Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application required the AESO to provide service under Rate FTS by charging not more than the “postage stamp rate” for operating reserve charges, voltage control (TMR), and other system support charges.

Title: Load level

Reference: Application, Rider H, p. 4

Preamble: “At the end of each billing period, the AESO will determine the incremental cost of the additional transmission must-run (TMR) dispatch of a fourth generator in the Rainbow Area, beyond the dispatch that would have been required prior to the addition of an incremental 10 MW of load near Fort Nelson in January 2008. Under this rider, 50% of the incremental cost so determined will be billed to BC Hydro.”

Request:

- (a) Please specify the MW limit of the BC Hydro's FTS contract.
- (b) Please confirm that Rider H is limited to a maximum of 10 MW's above the existing BC Hydro FTS contract level.
- (c) Please clarify if BC Hydro has applied for more than the 10 MW's of incremental Fort Nelson load. If so, please share the volume and expected in-service date(s) of any other applications.

Response:

- (a) BC Hydro has currently contracted for 38.5 MW at Fort Nelson, as explained on page 1 of the original Interim Rider H application.
- (b) As detailed in the Interim Rider H rate sheet, it addresses additional TMR dispatch “beyond the dispatch that would have been required prior to the addition of an incremental 10 MW of load near Fort Nelson in January 2008.”
- (c) BC Hydro has applied for an additional 5 MW of contract capacity effective as soon as practical, which is contingent on the full implementation of the automatic Under Voltage Load Shedding (UVLS) scheme in the Rainbow Area discussed in Information Response HARVEST.AESO-002 (e).

BC Hydro has also applied for a further 32 MW of contract capacity. Its in-service date will be contingent on the results of the AESO's detailed analysis and studies of the transmission system in the area with respect to accommodating the additional load.

Title: Transmission Must Run (TMR) Price Reconstitution

Reference: AESO Stakeholder session – January 29, 2009 – Review of Quick Hits Implementation

Preamble: At an AESO stakeholder session held on January 29, 2009, AESO representatives displayed a number of charts to assess the impact and success of the Quick Hits. The Quick Hits are a series of Alberta electric market rule changes that were fully implemented in 2008, that modified pool participant interaction with the AESO. The Quick Hits also included a change to the treatment of TMR in regards to the determination of Pool Price.

Request:

- (a) Please provide a copy of the PowerPoint slides that were presented at the referenced AESO stakeholder session?
- (b) At the above referenced stakeholder session, the AESO stated that in their opinion, the change in AESO rule that effectively reconstituted pool price for the volume of TMR dispatched, created over a \$5/MWh increase to the average pool price in all hours in the period studied (January – June, 2009). Please provide:
 - (i) The actual assessed \$/MWh impact.
 - (ii) The method used to calculate this impact? If possible, please share the relevant spreadsheets used in this assessment.
 - (iii) Please recalculate this assessment, after increasing the TMR dispatched in all hours by 10 MW?
 - (iv) Please contrast the impact calculated in (b) 3. in \$/MWh with the base impact described in (b) 1. above.
- (c) Please confirm and discuss the primary factors that impact the calculation of the reconstitution of the pool price. If not confirmed, please fully explain. In this discussion please consider a situation where the volume of TMR dispatched is increased as studied in (b) 3. above.
- (d) Please confirm that reconstituting Pool Price for the volume of TMR dispatched creates a higher pool price that is paid to all generators in the Province? If not confirmed, please fully explain.
- (e) Please confirm that the higher reconstituted pool price has the impact of increasing the total revenue that TMR units receive in payment from the AESO? If not confirmed, please fully explain.

- (f) Please confirm that BC Hydro, as a TMR supplier and Generator in the Fort Nelson region, receives benefits from the reconstituted pool price? If not confirmed, please fully explain.
- (g) Please consider and provide your opinion and comment fully on the following: The change in the Quick Hit rules regarding TMR pool price reconstitution creates a situation where every additional MW of TMR dispatched by the AESO's system controller creates a higher pool price which is paid to all Generators. Thus, it would follow that Rider H should include a charge to BC Hydro to recover this increase in the pool price paid by Alberta's electric consumers.

Response:

- (a) A copy of the PowerPoint slide related to TMR and DDS costs is provided as Attachment UCA.AESO-010 (a). The information contained in the slides was preliminary in nature and, as announced at the stakeholder meeting, the AESO Quick Hits presentation was intended to provide a general overview for information only.
- (b) Under the current ISO Rules, Dispatch Down Service (DDS) is in place to correct the artificial price depressing impact of TMR dispatch. When TMR is needed and dispatched anywhere on the Alberta Interconnected Electric System, the AESO will offset the impact of the out-of-merit energy caused by such dispatch by dispatching DDS which reduces energy production from an eligible in-merit generation asset. The net effect of the offsetting DDS dispatch is to leave the pool price at the unconstrained price level where it would have been but for the TMR dispatch. The cost of DDS is paid for by generators that were producing during the time DDS was dispatched and load is not allocated any DDS charges.

The Information Request is specifically referring to the AESO TMR analysis of the impact of the Quick Hits rule changes. Prior to December 2007 the out-of-merit energy provided from a TMR unit would artificially depress the pool price relative to the unconstrained level that existed before the TMR dispatch occurred. The TMR analysis presented at the stakeholder meeting included an estimate of the pool price had the Quick Hit rules, specifically the DDS rules, not been implemented.

The AESO believes that an analysis of the TMR market impact under conditions that might have occurred under an old set of ISO rules is not relevant to the current Interim Rider H Extension application. Under the current rules, incremental TMR caused by load changes in the Fort Nelson area does not artificially depress the pool price.

With that context, the AESO provides the following responses to the Information Request:

- (i) The preliminary estimate of the artificially depressing impact that TMR dispatch may have had on pool price under the pre-Quick Hits ISO rules using a specific static methodology is \$5.35/MWh over all hours in the January to June 2008 period.
- (ii) The TMR analysis requires extensive manipulation of a massive amount of data. The estimate was calculated by removing the DDS impact from the pool price for the period in question. This approach requires the manual manipulation of the

Energy Market Merit Order (EMMO) in every hour of every day during the six month review period. The methodology entails recalculating the marginal price as if DDS was not being provided. The price recalculation methodology does not take into account any market responses that would normally occur with a change in price. Based on the existing dispatch level, the new merit order with the DDS amount added back in was used to determine a new marginal price setter, at a price less than or equal to the reconstituted price. The resultant marginal price represents one possible price level that may have occurred if there was no DDS to offset the out of merit energy created by a TMR dispatch.

The AESO cannot share the TMR impact calculation worksheets because the calculation utilizes confidential customer information. Such information is clearly of a commercial and financial nature that is consistently treated as confidential by the AESO. The AESO considers that the provision of such information could result in harm to a customer's competitive position.

In addition, the amount of data involved in the calculation is extremely large and cannot be made available with reasonable effort.

The AESO therefore declines to provide the requested information due to both its confidentiality and the inability to provide it with reasonable effort, in accordance with sections 31(1)(b) and (c) of AUC Rule 001 Rules of Practice.

- (iii-iv) As indicated in part (ii) above, the TMR analysis requires the extensive manipulation of a massive amount of data. The AESO is unable to provide the specific information requested with reasonable effort.

The AESO would note, however, that a 10 MW change represents approximately 5 to 10% of the average TMR dispatched in 2008. The AESO estimates that the artificial price depressing impacts of a 10 MW change in TMR are within the range of accuracy of the methodology used to estimate the price impact of DDS.

It is also important to note that the price reconstitution that occurs through the use of DDS is limited to periods when the system marginal price is below the reference price. The reference price is 12.5 times the current gas price. This is important because as load increases it is reasonable to expect that price may increase accordingly, and at some point the price reconstitution no longer takes place.

- (c) Please refer to parts (b) (ii) and (iii-iv) above.
- (d) Under the current ISO Rules, DDS is a price reconstitution mechanism which mitigates the artificial price depressing effects that TMR may have on pool price. Prior to December 2007, under the ISO Rules in effect at that time, TMR dispatch may have artificially lowered the pool price when TMR was needed to relieve a constraint.
- (e) Under the current rules, DDS mitigates the artificial price depressing effects that TMR may have on pool price. All generators are paid pool price for energy produced. TMR providers are paid based on the pool price which tends to reduce variable cost payments relative to settlement under the pre-Quick Hits rules. TMR providers are paid the

difference between their variable cost and pool price, when pool price is less than their variable cost.

- (f) Part (e) above discusses how the reconstituted pool price affects TMR providers. All generators, whether providing TMR or energy, receive the pool price when generating. Powerex is the Fort Nelson TMR provider, not BC Hydro.
- (g) The change in the Quick Hit rules regarding DDS pool price reconstitution does not create a situation where every additional MW of TMR dispatched by the AESO creates an artificial increase in pool price. DDS mitigates the artificial price depressing effects that TMR may have on pool price. Hence, the AESO does not see a need to include an additional charge in Interim Rider H.

Title: Rider H recovery from Consumers

Reference: Rider H extension application

Preamble: Rider H describes the charge to BC Hydro and sharing of the associated cost for TMR with Alberta consumers. The UCA would like to clarify how this charge will be collected from other AESO transmission customers.

Request:

Please describe how the portion allocated to Alberta consumers for Rider H (50%) will be recovered through the AESO tariff?

Response:

As explained on page 5 of the original Interim Rider H application, "The remaining 50% of incremental costs will be recovered from other AESO customers through the AESO's Deferral Account Adjustment Rider C, as the costs were not included in the revenue requirement on which either current or applied-for rates were based."

When a final rate for service to BC Hydro is approved, either the AESO or BC Hydro will pay to the other party the difference between costs recovered under the interim rider and costs that would have been charged under the final rate. The final costs would then be included in the AESO's next deferral account reconciliation application and financially settled with AESO customers at that time.

Title: Impact of rate shock on BC Consumers rates

Reference: Decision 2005-096, p. 31

Preamble: "BCH noted that its costs would rise by approximately 2800%, an increase constituting rate shock....."

Request:

- (a) Please quantify and provide its own estimate of the percentage increase in BC Hydro and Power Authority's total costs that is expected with the interim Rider H charge?
- (b) Also, please quantify the same impact to BC Hydro, assuming that Rider H covered 100% of incremental TMR costs?
- (c) Please provide your assessment on the percentage increase outlined in (a) and if this level of increase constitutes rate shock?

Response:

- (a-b) On page 1-11 of its *F2009/F2010 Revenue Requirements Application* filed with the British Columbia Utilities Commission on February 20, 2008, BC Hydro summarized its 2009 and 2010 revenue requirements to be \$3,080 million and \$3,382 million, respectively.

As explained in Information Response AUC.AESO-001 (a-b), the AESO does not expect to assess any charges to BC Hydro under Interim Rider H in 2009 and 2010. The increase to BC Hydro's total costs in those years would therefore be 0% whether Interim Rider H charged 50% or 100% of incremental TMR costs to BC Hydro.

- (c) As there is no increase in costs expected, it would not constitute "rate shock".