



Alberta Electric System Operator and Husky Oil Limited

Husky Oil Limited Complaint Against AESO Fort Nelson Rider H

June 24, 2008



ALBERTA UTILITIES COMMISSION

Decision 2008-052: Alberta Electric System Operator and Husky Oil Limited
Husky Oil Limited Complaint Against AESO Fort Nelson Rider H
Application No. 1554646

June 24, 2008

Published by

Alberta Utilities Commission
Fifth Avenue Place, 4th Floor, 425 - 1 Street SW
Calgary, Alberta
T2P 3L8

Telephone: (403) 592-8845
Fax: (403) 592-4406

Web site: www.auc.ab.ca

Contents

1	INTRODUCTION	1
2	BACKGROUND	1
3	VIEWS OF THE PARTIES	3
4	COMMISSION FINDINGS	7
5	ORDER	10
	APPENDIX A – COPY OF ORDER U2008-2	11

**ALBERTA ELECTRIC SYSTEM OPERATOR
AND HUSKY OIL LIMITED**

Decision 2008-052

HUSKY COMPLAINT AGAINST AESO FORT NELSON RIDER H Application No. 1554646

1 INTRODUCTION

On January 10, 2008, Husky Oil Limited (Husky) filed a complaint (the Complaint) with the Alberta Utilities Commission (AUC or the Commission) in which Husky requested the Commission review Order [U2008-2](#), Electric Rates – Miscellaneous, Alberta Electric System Operator (AESO) Fort Nelson Rider H. Husky maintained that the AESO’s original application 1552173 requesting increased service to Fort Nelson understated the potential impact of additional service to Fort Nelson in British Columbia (BC) on the Rainbow Area System Reliability.

The Complaint was heard by way of a written proceeding with written Argument being received April 30, 2008 and written Reply being received May 14, 2008. The Commission therefore considers the close of record for the proceeding to be May 14, 2008.

2 BACKGROUND

On December 19, 2007, the AESO filed an application with the Alberta Energy and Utilities Board (the EUB or the Board) addressing the interim refundable recovery of costs related to the provision of certain incremental contract capacity to BC Hydro (BCH) to enable service to load at Fort Nelson, British Columbia. The Application was subsequently heard by the AUC on an expedited basis without a hearing process, leading to the issue of Order U2008-2 on January 2, 2008.¹ The additional service requested by BCH was to serve Harvest Energy Trust (Harvest).

In the original application the AESO explained that it provided service to BCH under Fort Nelson Demand Transmission Service Rate FDS. Rate FDS was approved by the Alberta Energy and Utilities Board (EUB) in Decision [2005-096](#),² Decision [2005-131](#),³ and Order [U2005-464](#).⁴ It was subsequently retroactively amended to reflect applicability revisions to the Balancing Pool Consumer Allocation Rider F and to correct an error arising from the use of an incorrect billing determinant in the calculation of the demand charge, through

¹ For the benefit of the interested reader a copy of Order 2008-2 is attached at the end of this Decision as Appendix A.

² Decision 2005-096 – Alberta Electric System Operator (AESO) 2005/2006 General Tariff Application (Application No. 1363012) (Released: August 28, 2005)

³ Decision 2005-131 – Alberta Electric System Operator (AESO) Refiling of 2005/2006 General Tariff Application per Decision 2005-096 (Application No. 1420890) (Released: December 6, 2005)

⁴ Order U2005-464 – Alberta Electric System Operator (AESO) 2nd Refiling of 2005/2006 GTA (Application 1434708) (Released: December 20, 2005)

Order [U2006-307](#)⁵ to be effective January 1, 2006. Rate FDS was most recently approved by the EUB in Decision [2007-106](#).⁶

The AESO explained that BC Hydro's FDS contract capacity up to early 2007 was 24.5 MW. In November 2006, BC Hydro requested the AESO to increase its contract capacity to 36.5 MW. In December 2006, BC Hydro requested an additional increase to 38.5 MW. The AESO approved an increase of 4 MW, to 28.5 MW, effective July 1, 2007, but delayed approving the remaining 10 MW until an assessment of operational constraints in the Rainbow Area could be completed.

With respect to the financial matters in the original application, the interim rider was based on recovering from BC Hydro about 50% of the cost of incremental TMR dispatch required by the provision of an additional 10 MW of contract capacity to BC Hydro. The AESO considered that the recovery of 50% of the costs reflected a fair apportionment of the incremental TMR costs until such time as the matter was given a final regulatory review and gave both parties incentive to cooperatively assess the long term needs of the Fort Nelson area and bring forward a longer-term tariff solution for EUB approval.

Husky took no issue with the financial matters related to the original application and approved by the Commission in the subsequent Order U2008-2.

With respect to the impact upon system reliability, the AESO stated in the original application that the additional TMR dispatch would slightly decrease current system reliability in the Rainbow Area. Under the current OPPs (Operating Practices & Procedures), three generators are dispatched for TMR service and a fourth generator is on standby for backup TMR dispatch in the event of planned or unplanned outages of one of the first three generators. To accommodate the additional load, the fourth generator is sometimes dispatched concurrently with the first three generators, which leaves no generator available for backup TMR dispatch. The four generators are dispatched on-line when Rainbow Area load exceeds 130 MW. If a planned or unplanned outage of one of the four generators then occurs, load services will be curtailed either in accordance with a plan designed for a specific contingency or in preparation for the second contingency.

The AESO considered the risk of such an occurrence to be relatively small and generally comparable to the risk of interruptions in other areas of the province. In addition, the reliability reduction would occur for only about 30% of the time, namely, in those hours in which the fourth TMR generator is dispatched.

To quantify the increased risk associated with dispatch of four TMR generators, the AESO compared the existing situation to the proposed situation.

Under the existing situation, using a binomial probability calculation and assuming the average availability of the Rainbow Area generation units is 94%, the probability of a second contingency (in which two or more units are off-line at the same time in any given period) is

⁵ Order U2006-307 – Alberta Electric System Operator Amendme2307nts to AESO 2006 Rider F and Rate FDS (Application No. 1482458) (Released: December 14, 2006)

⁶ Decision 2007-106 – Alberta Electric System Operator General Tariff Application for the Period January 1, 2007 to December 31, 2007 (Application 1485517) (Released: December 21, 2007)

about one percent. Loss of two or more units at the same time would result in some load services curtailment in the area for that time.

For the proposed situation, using the same calculation and availability assumptions, the AESO stated the probability of losing two or more units at the same time increased to only about two percent. The AESO considered that the impact on reliability would be comparable to that which would result from serving increased Alberta load in the Rainbow Area, and was therefore reasonable.

It is this AESO assessment of the effect upon system reliability in the Rainbow area that Husky took issue with in the Complaint.

3 VIEWS OF THE PARTIES

Husky noted that the original application documents indicated that when area load is greater than 130 MW the Rainbow Lake area requires all four generating units (Rainbow 2, 4, 5 and Fort Nelson) to be running, leaving no standby unit available. The trip or unavailability of one unit will not lose load but the loss of a second unit will. The lack of standby generation to cover unit maintenance periods as well as unplanned unit outages provided a greater exposure to risk of area load loss. Historically, area load has only been above 130 MW for about 20 hours annually. While Husky preferred that there be no additional exposure, given this relatively short period, Husky considered the risk to be tolerable. Husky was very concerned, however, when the application indicated the additional BC load could cause the Rainbow Lake area load to operate above 130 MW for more than 30% of the time, or 2600 hours/year. Husky believed this additional exposure would compromise the historical operating regime of the Rainbow Lake area.

Husky accepted that the operation proposed by the AESO when all four units were running met the strictest application of the WECC (Western Electric Coordinating Council) reliability criteria. Husky also noted that the AESO has indicated that the operation of generation in the Rainbow area is more a historic norm than a requirement to meet reliability standards. Husky maintained, however, that the historic operation of this area ensuring more generation than strictly required by the WECC Criteria was deliberate, primarily due to the major dependency on generation for area reliability. Husky pointed out that generators differ from transmission lines significantly both in terms of their reliability as well as their potential for extended outages.

However, since the filing of their complaint, the AESO supplied two significant pieces of information which have been put on the record in this proceeding and which effectively show that the “slight” impact on system reliability that the AESO identified in the first place has been largely if not entirely mitigated.

In particular, in Comm.AESO-001(a), the AESO revised its estimates of the percentage of hours that TMR dispatch above 130 MW would be needed from 30% to 22%. This minimized the slight impact on system reliability even further. Second, as a condition of providing the incremental service to BCH’s customer, Harvest, is subject to load curtailment. As noted by the AESO,⁷ “the load curtailment procedures described in HARVEST.AESO-002 (a-d) and the

⁷ Comm.AESO-001(b)

increased TMR dispatch requirements effectively result in the Rainbow Area reliability being unaffected by the addition of the BCH load”.

Husky acknowledged that the revisions to the AESO OPP 501 now include load shedding provisions applicable to the additional Fort Nelson load.⁸ Assuming those aspects of OPP 501 remain in effect and that the AESO ensures compliance with them, Husky stated the risk of adverse impact on the reliability of service to existing Rainbow Area customers should be mitigated.

Nevertheless, Husky remained concerned that OPP 501 allows British Columbia Transmission Corporation (BCTC) as much as 20 minutes to execute a curtailment instruction and preferred the AESO, BCH and BCTC implement an automated load curtailment scheme that would avoid the 20-minute delay.⁹ Husky conceded that the risk of a loss of a second Rainbow Area generator during the 20-minute period was comparatively small when considered solely on the basis of probabilities. Still, Husky maintained it must be appreciated that the risk of such an occurrence has been doubled with the addition of the new load.¹⁰ Moreover, many contingency events affecting rotating equipment (like the Rainbow Area generating units) do not necessarily conform with conventional probability theory particularly when common mode events such as extreme local weather can impact more than one unit simultaneously.

Husky expressed disappointment that the AESO has been unable to instead accommodate load growth by securing additional TMR resources in the Rainbow Area pending completion of the Northwest Alberta Transmission Development. Husky maintained recent oil and gas activity in northeast British Columbia suggested this was not a "one off" issue and that a proactive (i.e., generation-focused) solution should be pursued. In this regard, it was not clear to Husky that the AESO has pursued all available opportunities to arrange additional TMR. For example, although the AESO reported that ATCO Power has indicated that Rainbow Units 1 and 3 are unavailable for TMR service, Husky understood that Rainbow 1 was in fact available to run – albeit with limited running hours available.

In conclusion, however, Husky stated that assuming the relevant revisions to OPP 501 will remain in effect and that the AESO will ensure compliance with them, Husky no longer opposed the AESO Application.

BCH’s customer, Harvest, submitted that Husky had raised two primary concerns:

1. The Rainbow Lake area load could be greater than 130 MW for up to 30% of the time, causing increased risk of inadequate generation to serve loads in the Rainbow Lake area.
2. A more suitable short term solution needs to be developed to accommodate the increased load in the Rainbow lake area.

Harvest stated Husky’s first concern had been dealt with by the curtailment provisions of revised OPP 501.

⁸ HOL.AESO-003 (c)

⁹ OPP 501, at section 4.5

¹⁰ HOL.AESO-008 (a)

Harvest, however, shared Husky's concern that the proposed solution of running TMR generators more often and curtailing the Harvest load is not an appropriate short or medium term solution. Harvest stated the AESO appeared to be of the view that this solution was acceptable until the Northwest Alberta Transmission Development is implemented in 2011,¹¹ as noted in response to HOL.AESO-010 (c):

Until the planned Northwest Alberta Transmission Development is completed in the Rainbow Area, the AESO's Operating Policies and Procedures (OPP) 501 regarding Northwest Area Operations, revised March 1, 2008, provides that Harvest load will be curtailed when TMR generation is not adequate in the Rainbow Area.

Harvest submitted that curtailing load for a three year period was not appropriate.¹² In justifying that the incremental Harvest load should be curtailed, the AESO stated in response to HARVEST.AESO-002 (e):

When planning the addition of load in a constrained area, the AESO will assess reliability issues such as voltage stability and thermal overloads that may occur as a result of the additional load. If there is no practical way to accommodate the additional load in the constrained area without implementing load curtailment procedures, the additional load may be required to curtail before other loads until appropriate transmission system infrastructure can be provided to alleviate the constraint.

Harvest submitted that in addition to the options to not increase TMR dispatch, as noted in response to HOL.AESO-004 (e), the AESO should be evaluating all options to increase the capacity and/or number of TMR generators that could be used to avoid load curtailment. In particular, notwithstanding the response to Comm.AESO-002 (a) & (b), Harvest submitted that the AESO should be expediently pursuing options to minimize the curtailment of the Harvest load, and any additional incremental load that materializes in the Rainbow Lake area.

Harvest suggested the Commission provide the following directions to the AESO:

1. To investigate and implement on an expedient basis alternate measures to minimize the curtailment of loads in the Rainbow Lake area prior to the implementation of the Northwest Alberta Transmission Development in 2011, through transmission upgrades and/or the addition of incremental TMR generating capacity.
2. To treat all incremental Rainbow Lake load in a similar manner to the treatment of the Harvest load, as outlined in OPP 501.
3. To expediently resolve customer interconnection issues, regardless of the nature or location of the end-use customer.

Harvest stated that the AESO appeared to agree with the second recommendation, given its response to HOL.AESO-003(d):

The AESO would generally expect to treat any future new loads, or increases to existing loads, in a similar manner as the Harvest load until appropriate transmission system infrastructure can be provided to alleviate system constraints.

¹¹ The transmission upgrades to support the Rainbow lake area are currently proposed to be in-service by April, 2011 (Comm.AESO-002 (c))

¹² Harvest notes that it has been curtailed since being connected in early March 2008.

With respect to the third recommendation, however, Harvest expressed disappointment in the considerable time that has lapsed between Harvest being ready to interconnect in August 2007 and the actual interconnection in March 2008. In Harvest's submission, this delay could have been eliminated, and considerable expense to Harvest mitigated, if the AESO and BC Hydro would have addressed the issues in a more appropriate and timely manner.

In its reply to Husky's argument regarding the increased risk during the 20 minute period between a TMR generation contingency and when the Harvest load is curtailed, Harvest submitted that 20 minute notice is industry standard where operator intervention is required to curtail load. Harvest stated this risk can be mitigated with the additional procurement of TMR capacity in the Rainbow lake area.

In conclusion Harvest submitted the Husky complaint should be dismissed and that Rider H should remain in effect.

The AESO maintained that the impact on reliability was reasonable, noting that after receiving approval of Rider H, the AESO proceeded to develop load curtailment procedures as described in Information Response HARVEST.AESO-002 (a-b). In particular the AESO stated the curtailment of Harvest load prior to any other loads essentially restored the Rainbow Area system to the status that would have existed without the connection of the Harvest load, under the defined conditions based on AESO Operating Criteria.

The AESO observed that Husky had stated the potential loss of standby generation the Rainbow Lake area was now facing is similar to that which occurred in late 2005 and again in late 2006. The AESO also stated Husky acknowledged the AESO helped alleviate these concerns in 2005 by promising to evaluate each generator outage individually and dispatch one of the non TMR units prior to the loss of a second generator if this was warranted and that the AESO responded to this dilemma in 2006 by extending the TMR agreement of Rainbow 2.

The AESO submitted its response in the current case had a similar effect in addressing the specific circumstances giving rise to reliability concerns. In particular, the AESO explained its rationale for the new load curtailment procedures in Information Response HARVEST.AESO-002 (e):

When planning the addition of load in a constrained area, the AESO will assess reliability issues such as voltage stability and thermal overloads that may occur as a result of the additional load. If there is no practical way to accommodate the additional load in the constrained area without implementing load curtailment procedures, the additional load may be required to curtail before other loads until appropriate transmission system infrastructure can be provided to alleviate the constraint. Alternatively, the additional load may decide not to be connected to the system until such infrastructure is in place. Existing load does not have similar options, such as delaying interconnection, available to it.

The AESO submitted its proposed curtailment of the Harvest load was consistent with its historical practice, and addressed the current concerns of Husky in a manner similar to that which addressed Husky's prior concerns about reliability in the Rainbow Area.

The AESO stated Husky had raised a number of other issues, including:

- the extended running time of existing generators dispatched for TMR service;
- AESO plans in the event of a catastrophic failure of a generating unit;
- coordination of generator maintenance schedules;
- load restoration plans; and
- area load shed methodology.

The AESO claimed these were not directly related to the provision of incremental service to BCH, had limited impact on the service to Husky load, and were not relevant to consideration of the Complaint. However, the AESO noted that information on these issues was provided in Information Responses Comm.AESO-001 (c), HARVEST.AESO-001 (b-c), HOL.AESO-003 (c), and HOL.AESO-009 (m).

The AESO acknowledged the operational concerns that exist in the Rainbow Area and that were referred to in parties' arguments. The AESO stated it has developed, and continues to develop, specific responses to changing circumstances that affect dispatch of TMR generation in the Rainbow Area. The AESO outlined its approach to addressing operational concerns in Information Responses HARVEST.AESO-002 (e), HOL.AESO-003 (d), and HOL.AESO-010 (a-b).

The AESO specifically noted suggestions that it attempt to contract additional units to provide TMR service in the Rainbow Area. The AESO did not consider the cost of contracting with an additional TMR generator to be either appropriate or reasonable, given that under revised OPP 501, the reliability of the Rainbow Area system has been essentially restored to the status that would have existed without the connection of the Harvest load, as discussed in Information Response HARVEST.AESO-002 (d). The AESO stated it would respond to circumstances as they change in the Rainbow Area and, if appropriate, would investigate contracting with an additional TMR generator in the future.

Since Husky, as the applicant, no longer opposed the AESO's Application, the AESO submitted that the Husky Complaint should be dismissed.

4 COMMISSION FINDINGS

In their arguments the AESO, BCH and Harvest all stated the Complaint should be dismissed and that Rider H should be confirmed. Husky itself stated:

Assuming that the relevant revisions to OPP 501 will remain in effect and that the AESO will ensure compliance with them, Husky no longer opposes the AESO Application.

The Commission finds that Husky is effectively dropping its complaint. As no party has indicated any ongoing opposition to Rider H, the Commission confirms the approval of Rider H, for the reasons given in Order U2008-2, and dismisses the Complaint of Husky. In addition to the reasons provided in Order U2008-2 the Commission also found the Information Responses provided by the AESO in this process to provide persuasive reasons for the dismissal of the Complaint.

In particular, in Comm.AESO-001, the AESO explained that the load curtailment procedures described in information response HARVEST.AESO-002 (a-d) and the increased TMR dispatch requirements effectively result in the Rainbow Area reliability being unaffected by the addition of the BC Hydro load. The AESO placed the issue of reliability in the Rainbow area in further perspective in HOL.AESO-008 when it responded as follows:

Many areas of the province are either fed radially from transmission and distribution facilities or, if fed from two transmission facilities, are unable to serve all loads following a second contingency.

The availability of a standby generator in the Rainbow Area is generally considered to provide greater reliability compared to other areas where reliability depends solely on radial transmission facilities. The addition of the Harvest load will result in a standby generator being utilized during times when dispatch of four TMR generators is required (i.e. it is therefore not available for standby service) and accordingly slightly decreases the reliability to a level more comparable to other areas where reliability depends solely on radial transmission facilities.

In HOL.AESO-002 the AESO referred to Article 13 (should be 17) of its Terms & Conditions which deal with service interruptions. Article 17.1 states as follows:

Service Not Guaranteed

Although precautions are taken to guard against System Access Service interruptions, the AESO does not guarantee uninterrupted System Access Service. The AESO specifically does not guarantee uninterrupted System Access Service in respect of interruptions caused by:

- (a) scheduled or planned facility maintenance activities;
- (b) construction, commissioning and facility testing activities;
- (c) unscheduled or unplanned events (such as, but not limited to, emergency equipment maintenance and Emergencies);
- (d) Force Majeure;
- (e) breaches of obligations owed to the AESO by its suppliers or Customers; or
- (f) as otherwise expressly allowed by a Rate Schedule.

Whenever System Access Service has been interrupted, diminished or reduced for reasons other than a breach of this Tariff by the Customer, the AESO will make all reasonable efforts to ensure that service is restored as soon as practicable after the interruption, diminution or reduction.

In addition to the Complaint, both Harvest and Husky have raised the issue of what additional efforts, if any, the AESO should undertake to provide reliable service to the Rainbow area. The AESO responded to these suggestions in reply when it stated:

The AESO specifically notes suggestions that it attempt to contract additional units to provide TMR service in the Rainbow Area. At this time, the AESO does not consider the cost of contracting with an additional TMR generator to be either appropriate or reasonable, given that under revised OPP 501 the reliability of the Rainbow Area system has been essentially restored to the status that would have existed without the connection of the Harvest load, as discussed in Information Response HARVEST.AESO-002 (d). However, as discussed above, the AESO will respond to circumstances as they change in

the Rainbow Area and, if appropriate, will investigate contracting with an additional TMR generator in the future.¹³

In response to HOL.AESO-008, the AESO also stated:

Consequences of load curtailments are generally more severe in cold weather than in other seasons. It should be noted that even with just one generator available in the Rainbow Area, there is adequate capacity power to service heat and light requirements for industries and communities such that equipment freeze-up can be prevented, although facilities would not be able to operate at full demand.

To assist in reducing the impact of a load curtailment, curtailed load is rotated every half-hour to an hour. Furthermore, customers are advised to have their own contingency plan in case load interruption affects their business severely, as uninterrupted electrical supply is generally not guaranteed.

In the Commission's view the AESO must be mindful of increased and, as the AESO has noted, potentially unreasonable costs, that it would have to justify to all its stakeholders. The Commission finds that the AESO has demonstrated that the reliability level in the Rainbow area has been restored to that prevailing before the addition of the Harvest load by the amendments to OPP 501. Additionally, the AESO has noted that reliability in the Rainbow area is equal to or better than that offered to many other customers in other parts of the Province served by radial lines.

In light of the above evidence, the Commission does not consider it necessary to offer any additional direction to the AESO.

¹³ AESO Reply, page 2

5 ORDER

IT IS HEREBY ORDERED THAT:

- (1) The Complaint by Husky Oil Limited is denied and Rider H is confirmed.

Dated in Calgary, Alberta on June 24, 2008.

ALBERTA UTILITIES COMMISSION

(original signed by)

Thomas McGee
Chair

(original signed by)

Bill Lyttle
Commissioner

(original signed by)

Tudor Beattie, Q.C.
Commissioner


APPENDIX A – COPY OF ORDER U2008-2



Appendix A - EUB
Order U2008-2.pdf

(consists of 6 pages)

Electric Rates - Miscellaneous Order U2008-2

<p>MADE at the City of Calgary, in the Province of Alberta, on 2nd day of January 2008.</p>	 ALBERTA ENERGY AND UTILITIES BOARD
<p>Alberta Electric System Operator Fort Nelson Rider H Application</p>	<p>Application No. 1552173</p>

1 INTRODUCTION

On December 19, 2007 the Alberta Energy and Utilities Board (the Board or EUB) received an application (the Application) from the Alberta Electric System Operator (AESO) in which the AESO requested approval of an Interim Refundable Fort Nelson Rider H, to be effective on an interim refundable basis from January 1, 2008, to December 31, 2008. The Application concerned the recovery of costs related to the provision of certain incremental contract capacity to BC Hydro to enable service to additional load at Fort Nelson, British Columbia.

In order to process this application expeditiously, it has been reviewed without the provision of notice, pursuant to Section 58 of the *Public Utilities Act*. Section 58(2) of the *Public Utilities Act* provides for the following:

58(2) A person entitled to notice and not sufficiently notified may, at any time within 10 days after becoming aware of any order or decision, or within any further time the Board may allow, apply to the Board to alter or rescind the order or decision, and the Board shall, on that application and on any notice to the other parties interested that in its discretion it thinks desirable, hear the application, and either alter or rescind the order or decision or dismiss the application as to it seems just.

2 DETAILS OF THE APPLICATION

BC Hydro is a customer of the AESO in the northwest part of Alberta. The AESO currently provides service from Rainbow Lake in Alberta to BC Hydro near the provincial border, and BC Hydro in turn serves the community of Fort Nelson as well as industrial loads in this area of British Columbia.

The AESO stated it currently provides service to BC Hydro under Fort Nelson Demand Transmission Service Rate FDS. Rate FDS was approved by the EUB through Decision 2005-096, Decision 2005-131, and Order U2005-464. It was subsequently retroactively amended to reflect applicable revisions to the Balancing Pool Consumer Allocation Rider F and to correct

an error arising from the use of an incorrect billing determinant in the calculation of the demand charge, through Order U2006-307 to be effective January 1, 2006. Rate FDS was most recently approved by the EUB in Decision 2007-106.

BC Hydro's FDS contract capacity up to early 2007 was 24.5 MW. In November 2006 BC Hydro requested the AESO to increase its contract capacity by 12 MW, to 36.5 MW. In December 2006 BC Hydro requested an additional increase of 2 MW, to 38.5 MW.

The AESO stated it approved an increase of 4 MW, to 28.5 MW, effective July 1, 2007, but delayed approving the remaining 10 MW until an assessment of operational constraints in the Rainbow Lake Area could be completed.

The assessment was completed in August 2007 and indicated that the additional 10 MW of load in British Columbia could be accommodated, but would require significant additional dispatch of transmission must run (TMR) generation in the Rainbow Lake Area. The AESO stated that, in conjunction with BC Hydro, it began discussing alternatives that would allow service to the additional load without requiring additional TMR. Eventually six separate alternatives were considered, with some having one or more variations.

The AESO stated that none of these alternatives is expected to be able to accommodate the additional BC Hydro load in less than a minimum of six months, and all require studies to be completed to determine their effectiveness, cost, and operational requirements. Some of the alternatives are expected to also require additional significant expenditures in time and resources.

None of the alternatives is therefore able to respond to the immediate needs of the BC Hydro customer. Both the AESO and BC Hydro have agreed that the only practical solution to provide service in the short term involves the additional dispatch of TMR generation and thus incurs additional TMR costs.

The AESO stated studies undertaken to evaluate the additional 10 MW FDS contract capacity increase indicate that additional TMR dispatch volumes will be required for Rainbow Lake Area loads from 111 MW to 130 MW, and a fourth TMR generator will be required when Rainbow Lake Area load exceeds 130 MW. Operating Policies and Procedures (OPP) 501 is under review to reflect the results of these studies, and will be further updated if necessary based on an evaluation of TMR requirements in the Rainbow Area after the additional 10 MW of BC Hydro load is operational.

The AESO concluded that maintaining system reliability for an FDS contract capacity of 38.5 MW requires TMR dispatch of a fourth Rainbow Lake Area generator whenever area load exceeds 130 MW. The additional TMR dispatch of the fourth generator would be the primary cause of additional costs attributable to the increase in BC Hydro load. Additional costs would also be incurred through greater TMR dispatch volumes for three generators when Rainbow Lake Area load is between 111 and 130 MW. Without the additional 10 MW FDS contract capacity, neither the dispatch of a fourth TMR generator nor greater TMR dispatch volumes for three generators would be required under normal operating conditions.

While reviewing the technical alternatives to accommodate the increased load, the AESO stated it and BC Hydro also discussed commercial terms regarding payment for the incremental service to BC Hydro. Both the AESO and BC Hydro agreed that any service by the AESO to BC Hydro load should continue to be subject to regulatory oversight as necessary by the EUB in the determination of an appropriate rate for that service.

Both parties acknowledge that the EUB reviewed and determined the structure and approach of the current Rate FDS under which service is provided to BC Hydro at Fort Nelson in the AESO's 2005-2006 General Tariff Application. In the AESO's view, that rate 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. The AESO stated that in BC Hydro's view, however, 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.

Financial Impact

In view of the need to obtain a relatively quick solution to accommodate the BC Hydro customer's increased load, both parties agree that the matter should be further reviewed and considered by the Alberta Utilities Commission (AUC). In the meantime, both parties have recommended to the EUB, and requested approval of the Interim Refundable Fort Nelson Rider H. The interim rider is based on recovering from BC Hydro about 50% of the cost of incremental TMR dispatch required by the provision of an additional 10 MW of contract capacity to BC Hydro.

The AESO maintained recovery of 50% of the costs reflects a fair apportionment of the incremental TMR costs until such time as the matter is given a final regulatory review, and provides both parties incentive to cooperatively assess the long term needs of the Fort Nelson area and bring forward a longer-term tariff solution for AUC approval. The remaining 50% of the costs would, for the time being, be recovered from other AESO customers through the AESO's Deferral Account Adjustment Rider C, as these costs were not included in the AESO's 2007 revenue requirement forecast.

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.

Specifically, the amount to be recovered from BC Hydro under Rider H would be 50% of the incremental cost of TMR dispatch of a fourth generator in the Rainbow Area. Costs for the TMR dispatch of a fourth generator, above those costs associated with maintaining such a generator on standby, would be determined at the end of each month; 50% of those costs would be billed to BC Hydro, in addition to charges attributable to BC Hydro's load under Rate FDS for the month.

The AESO also noted that Section 48 of the 2007 *Transmission Regulation*, A.R. 86/2007, determines that costs for the provision of ancillary services (which include TMR services) are considered to be “prudent” or “appropriate” when such costs have been approved by the ISO members (being the AESO Board). The AESO stated the AESO Board has been advised of the costs of incremental TMR dispatch associated with accommodating the additional BC Hydro load and is supportive of the proposed approach to respond to the request for increased FDS contract capacity through incremental TMR dispatch or other means as considered reasonable by the AESO.

The AESO stated both parties agreed that the approval of an interim refundable rider would accommodate the immediate need for service, allowing issues to be appropriately determined and resolved before the AUC at a future date. The AESO and BC Hydro expect to further discuss and review the commercial terms regarding payment for the incremental service to BC Hydro, prior to submitting a final rate or rider application to the AUC.

The AESO also expects to include in the final rate application further information relating to longer-term transmission supply in the Rainbow Lake Area, including the impact of the Northwest Alberta Transmission Development. However, a complete long term transmission plan for the area is not expected to be able to be developed in time for inclusion in the final rate application.

Reliability Impact

With respect to the impact upon system reliability the AESO stated the additional TMR dispatch will slightly decrease current system reliability in the Rainbow Lake Area. Under the current OPPs, three generators are dispatched for TMR service with a fourth generator on standby for backup TMR dispatch in the event of planned or unplanned outages of one of the first three generators. To accommodate the additional load, the fourth generator will sometimes be dispatched concurrently with the first three generators, which therefore means no generator will be available for backup TMR dispatch.

During any period in which four generators are dispatched on-line when Rainbow Lake Area load exceeds 130 MW, if a planned or unplanned outage of one of the four generators occurs no backup TMR generator will be available. Load services will then need to be curtailed either in accordance with a plan designed for a specific contingency or in preparation for the second contingency.

However, the AESO considered the risk of such an occurrence to be relatively small and generally comparable to the risk of interruptions in other areas of the province. In addition, the reliability reduction will occur for only about 30% of the time, namely, in those hours in which the fourth TMR generator is dispatched.

To quantify the increased risk associated with dispatch of four TMR generators, the AESO compared the existing situation to the proposed situation.

Under the existing situation, using a binomial probability calculation and assuming the average availability of the Rainbow Lake Area generation units is 94%, the probability of a second contingency (in which two or more units are off-line at the same time in any given period) is about one percent. Loss of two or more units at the same time would result in some load services curtailment in the area for that time.

For the proposed situation, using the same calculation and availability assumptions, the AESO stated the probability of losing two or more units at the same time increased to only about two percent.

The AESO stated the reliability impact of all the alternatives being considered to serve the incremental BC Hydro load will be assessed as part of the application to the AUC for a final rate determination on this matter. The reliability impact of incremental TMR dispatch under the interim rider will therefore be limited in duration, as the interim rider is expected to be replaced by a final rate or rider within a year.

The AESO also stated it has advised other large customers in the Rainbow Lake Area of the potential reliability impact of incremental TMR dispatch. Ultimately, the AESO considered that the impact on reliability would be comparable to that which would result from serving increased Alberta load in the Rainbow Lake Area, and is therefore reasonable.

3 BOARD FINDINGS

The Board has reviewed the Application and considers it reasonable for the AESO to co-operate with BC Hydro to provide the additional service requested.

With respect to the financial impacts of the rate the Board considers that on an interim basis the proposed 50/50 sharing of costs between BC Hydro and other AESO customers to be reasonable. In particular the Board notes that the forecast increase in DTS revenue requirement is only 0.5%.

The Board accepts the evidence of the AESO that the addition of this service and the interim refundable Fort Nelson Rider H will have minimal impact on system reliability.

The Board therefore considers the proposed interim rate to be reasonable and is approved as filed.

4 ORDER

IT IS THEREFORE ORDERED THAT:

- (1) The Interim Refundable Fort Nelson Rider H is approved as filed (Appendix 1), effective January 1, 2008.

APPENDIX 1

ALBERTA ELECTRIC SYSTEM OPERATOR

Rider H **Interim Refundable Fort Nelson Rider H** Page 1 of 1

Purpose: The Interim Refundable Fort Nelson Rider H is to recover 50% of the cost of the additional transmission must-run (TMR) dispatch of a fourth generator in the Rainbow Area in support of incremental load near Fort Nelson.

Applicable to: BC Hydro for demand service to Fort Nelson in British Columbia.

Effective: The rider will be effective from January 1 to December 31, 2008, and will expire unless revoked or replaced by another approved rate or rider on or before December 31, 2008.

Rate: 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.

Terms: (a) Rider H is an incremental refundable charge in addition to amounts payable for demand and energy under Rate FDS.

 (b) The Terms and Conditions form part of this Rate Schedule.

END OF DOCUMENT