



June 4, 2009

*Posted on AESO website*

DTS Operating Reserve Charge Design Working Group Members  
AESO Stakeholders

Dear Working Group Member:

**Re: Meeting Agenda for DTS Operating Reserve Charge Design Working Group**

The first meeting of the DTS Operating Reserve Charge Design Working Group for the AESO's 2010 tariff application is scheduled as follows:

Time: 1:00 to 3:00 PM  
Date: Friday, June 5, 2009  
Location: Meeting Room 2538, AESO Office, 330 – 5th Avenue SW, Calgary  
Refreshments: Coffee, juice, and soft drinks

This working group includes the following members:

- ADC: Colette Kearn
- AltaLink: Hao Liu
- ENMAX: Randy Stubbings
- IPCAA: Vittoria Bellissimo
- TransCanada: Vince Kostas
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

- |   |  |         |
|---|--|---------|
| 1 | <b>Introductions</b>   | 1:00 PM |
|   | <ul style="list-style-type: none"><li>• Please indicate which stakeholders you represent</li></ul>   |         |
| 2 | <b>Review agenda</b>   | 1:10 PM |
| 3 | <b>Review draft working groups terms of reference</b>  | 1:15 PM |
|   | <ul style="list-style-type: none"><li>• See enclosed document originally posted on April 22, 2009</li><li>• The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:<ul style="list-style-type: none"><li>– Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.</li></ul></li></ul> |         |

- A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.
- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 **Background for DTS operating reserve charge design** 1:20 PM

- Please review the enclosed information before the meeting, if possible:
  - (a) Discussion of ancillary services cost classification in section 4.3 (pages 11-15) of the AESO's 2006 General Tariff Application, dated January 28, 2005
  - (b) Discussion of ancillary services cost classification in section 5.4 (pages 24-25) of Decision 2005-096 on the AESO's 2005-2006 General Tariff Application, released on August 28, 2005
  - (c) Discussion of ancillary services 2008 cost variances in section 3.1.2 (pages 34-37) of the AESO's 2008 Deferral Account Reconciliation Application, filed on April 9, 2009 (incorrectly dated April 9, 2008)
- The following costs were included in Table 2-2 in the AESO's 2009 Rates Update Application (filed on March 12, 2009) for recovery through the operating reserve charge.

Line No.	Description	2009 AESO Board		2008	2007
		Updated TFO Costs	Decision 28 Jan 2009	AESO Board Decision	Approved U2008-217
<b>Operating Reserves</b>					
Active					
16	Regulating	59.1	59.1	57.3	34.7
17	Spinning	86.9	86.9	78.7	41.1
18	Supplemental	77.7	77.7	69.4	32.0
19	<b>Subtotal Active Reserves</b>	<b>223.7</b>	<b>223.7</b>	<b>205.4</b>	<b>107.8</b>
Standby					
20	Regulating	6.2	6.2	4.7	4.6
21	Spinning	4.1	4.1	3.6	5.7
22	Supplemental	1.6	1.6	1.4	3.1
23	<b>Subtotal Standby Reserves</b>	<b>11.8</b>	<b>11.8</b>	<b>9.7</b>	<b>13.4</b>
24	Trading fees & other related charges	-	-	-	-
25	<b>Subtotal Operating Reserves</b>	<b>235.5</b>	<b>235.5</b>	<b>215.1</b>	<b>121.2</b>
<b>Other Ancillary Services</b>					
26	Brazeau Fast Ramp (Previously GRAS)	-	-	0.7	0.6
27	Black Start	2.9	2.9	2.0	2.8
33	Generator Remedial Action Schemes (RAS)	-	-	-	0.5
-	<b>Costs Included in Operating Reserve Charge</b>	<b>238.4</b>	<b>238.4</b>	<b>217.9</b>	<b>125.2</b>

- Is there other background that participants consider particularly relevant?

- 5      **DTS operating reserve charge discussion paper**      1:30 PM
- See enclosed discussion paper for proposed approach to revising DTS operating reserve charge
  - Review content of discussion paper
  - Discuss process to finalize discussion paper, including inviting comments from larger stakeholder audience
- 6      **Potential hourly allocation of operating reserve costs**      2:00 PM
- Can all operating reserve costs be allocated on an hourly basis?
  - What visibility of data would customers require for verification of operating reserve charges?
  - Are accurate operating reserve charges required for preliminary statements issued on the 5th business day of month?
  - How can adequate time be created to allow the AESO to calculate bills when operating reserve costs are finalized at the same time as DTS bills are issued?
  - What is needed to address these and other questions if hourly allocation of operating reserve costs is pursued?
- 7      **Follow-up required for next meeting**      2:45 PM
- Summarize what tasks need to be completed before next meeting and who will complete them
- 8      **Dates and times for next meeting(s)**      2:55 PM
- 9      **Adjourn**      3:00 PM

This agenda and all other printed information related to the DTS Operating Reserve Charge Design Working Group are available on the AESO's website at [www.aeso.ca](http://www.aeso.ca) by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders' participation in this consultation.

If you have any comments or questions on this consultation process or the AESO's tariff application, please contact me at 403-539-2465 or [john.martin@aeso.ca](mailto:john.martin@aeso.ca), or Raj Sharma at 403-539-2632 or [raj.sharma@aeso.ca](mailto:raj.sharma@aeso.ca).

Sincerely,

*[original signed by]*

John Martin  
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO

## AESO 2010 Tariff Consultation Working Groups Terms of Reference

### 1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO's 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

### 2 Topics

Working Groups are proposed to examine the following topics for the AESO's 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

- (a) **POD Cost Function and Investment Level Update**
  - Substations included in POD cost data set
  - Inflation index to escalate POD cost data to 2010
  - Multiplier to determine investment level
- (b) **TFO O&M Cost Causation Study**
  - Respond to AUC directions on analysis of TFO O&M costs
  - Determine if TFO O&M costs are energy-related
  - Determine if TFO O&M costs should be functionalized similarly to capital costs
- (c) **DTS Operating Reserve Charge Design**
  - Methodology to analyze and assess design of operating reserve charge
  - Criteria for selection of appropriate design for operating reserve charge
- (d) **Fort Nelson Rate FTS**
  - Rate design principles for Fort Nelson and similar services
  - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
  - Contractual considerations for Fort Nelson and similar services
- (e) **Export and Import Rates XTS and ITS**
  - Rate design principles for higher-priority export and import services
  - Similarities and differences between domestic and intertie services
  - Potential allocation of "deep system" costs to services over merchant interties
- (f) **Deferral Account Riders B and C**
  - Rate design principles for deferral account riders
  - Practicality of improving allocation accuracy of deferral account riders
  - Possible integration of Riders B and C

- (g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
  - Common provisions that could be standardized and consolidated
  - Dispersed information that could be consolidated
- (h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
  - Potential provisions for amortized customer contribution option
  - Assessment of credit-worthiness and mitigation of risk of default
- (i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
  - Assessment of Primary Service Credit and associated investment factor
  - Application of substation fraction at customer-owned substations

### **3 Working Group Members**

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.

- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

### **4 Duration**

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.

- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO's 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

### **5 Scope and Duties**

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO's 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.

- (a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.
- (b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.
- (c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.
- (d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at [www.aeso.ca](http://www.aeso.ca) by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.
- (e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

## **6 Deliverables**

The AESO 2010 Tariff Consultation Working Groups will provide the following.

- (a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.
- (b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.

- (c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

## **7 Principles**

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO's mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO's tariff.

## **8 Expenses**

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

## **9 Recent AESO Tariff Decisions**

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- AUC Decision 2008-037: AESO 2007 General Tariff Application Refiling (released on May 8, 2008)
- EUB Decision 2007-106: AESO 2007 General Tariff Application (released on December 21, 2007)
- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
- EUB Decision 2005-131: AESO Refiling of 2005/2006 General Tariff Application per Decision 2005-096 (released on December 6, 2005)
- EUB Decision 2005-096: AESO 2005/2006 General Tariff Application (released on August 28, 2005)

The classification of ancillary services costs, however, has been adjusted from that underlying the current tariff, based on the results of an ancillary services cost study discussed more fully in the following section.

5 The classification of costs for DTS customers is provided in Schedule 5.3, and for STS customers in Schedule 5.5.

### 4.3 Ancillary Services Cost Study

10 In Decision 2001-32 on the ESBI Alberta Ltd. (EAL) 2001 General Tariff Application Phase II Matters, the EUB provided the following direction:

- 15 10. *Therefore, the Board directs EAL, in the 2003 GTA, to file a more detailed and accurate cost of service study for system support services. Further, the Board directs that this cost of service study should contain the rationale for the allocation of each one of the following SSS [system support services] cost components:*
- *Operating Reserves (including regulating reserves, spinning reserves and supplemental reserves)*
  - *Generator RAS and Black Start*
  - *Load Following*
  - *Voltage Control (including TMR/SMR, hydro motoring, and ATCO Power's Poplar Hill's plant)*
  - *Remedial Action Schemes (including ILRAS)*
- 25 11. *The Board also directs EAL, in the 2003 GTA, to include rate proposals for unbundling SSS and proposals for customer self-supply of SSS.*

30 In accordance with this direction, the AESO commissioned EnVision Energy Consulting Ltd. to prepare an independent *Ancillary Services Cost of Service Study* (the AS Cost Study), attached as Appendix C to this Application. The study examined the costs incurred by the AESO to provide ancillary services, analyzed the factors that drive ancillary service requirements, and reviewed the match between the AESO's costs and the revenues derived from the current tariff. After concluding that the current rate structure can lead to mismatches between costs and revenues, the study recommended alternative rate designs which may provide a better match.

40 Ancillary services costs to the AESO can also be viewed as a function of payments to ancillary service providers, and can be classified for rate design purposes as demand-related or usage-related. The costs could then be recovered through tariffs as fixed or variable charges, in accordance with the classification of the ancillary service payments. Basing rate design for ancillary services solely on alignment with payments to ancillary services providers may not always accord with the cost classification set out in the AS Cost

Study, as cost causation is only one of several rate design criteria. In particular, the AESO is proposing ancillary services rates that also consider rate stability, simplicity of understanding, and economy of billing.

5 In Decision 2001-32, the EUB also noted “that the first step to self-provision [of ancillary services] is to unbundle the various system support services in the TA’s tariff” (p. 41) and provided Direction 11 to “include rate proposals for unbundling SSS and proposals for customer self-supply of SSS” (p. 59). Based on the AS Cost Study and rate design considerations, the AESO proposes to unbundle certain ancillary services. The AESO  
10 recognizes that each of the many individual ancillary services (as detailed in the AS Cost Study) could be identified separately in the rate schedule, but considers such detailed unbundling would be premature and would unnecessarily complicate billing during the time that the market for such services is developing. For example, the AS Cost Study concludes that the cost of regulating reserves should be classified in accordance with customers’  
15 ranges of demand over a given period. Rates designed on this basis would degrade rate stability on an individual customer basis, and would also increase billing costs as extensive information system changes to the billing and metering systems would be required to support the resulting tariffs.

20 Accordingly, the AESO has unbundled ancillary services into three separate and distinct tariff charges categorized by separate cost recovery approaches:

- (a) operating reserves charge, structured as a usage charge which varies as a percentage of pool price, averaged over all hours;
- (b) voltage control charge, structured as a flat (non-varying) usage charge; and
- 25 (c) other system support services charge, structured as a demand charge.

**Operating reserves** — Operating reserves consist of regulating reserves (including load following) and supplemental and spinning reserves (“contingency reserves”).

30 Regulating reserves in Alberta track variations in load that cannot be met with energy dispatches. Volumes of regulating reserves are specified as a range in MW over which a level of control is required by the automatic generation control system. The AS Cost Study concludes that regulating reserves are a function of the variability, or range, of Alberta Interconnected Electric System (AIES) load in each hour. The AESO’s operating policies  
35 have established a minimum regulation range — the difference between system supply and demand — of 110 MW. As the AESO makes payments to generators that assist the AESO in balancing supply and demand within that regulation range, the cost of regulating reserves is determined by the variability in the regulating range. Consequently, the AS Cost Study classifies regulating reserves as the range in demand over each hour.

40 Supplemental and spinning reserves are used to restore frequency following the loss of generation in Alberta or the Western Electricity Coordinating Council (WECC) area. In Alberta, the supplemental and spinning reserves requirement is primarily a function of the



AIES firm load responsibility served by hydro and thermal generation. The AS Cost Study concludes that costs of contingency reserves should therefore be classified as flat usage.

5 The AS Cost Study further concludes that the AESO's costs to procure operating reserves are dependent on several volatile inputs that are not correlated with each other. To avoid passing this volatility through to rates, the AESO is proposing to continue to recover these costs through an average all-hours percent of pool price, as approved in EUB Decision 2001-49 on the EAL 2001 GTA Final Rates and Tariffs.

10 **Generator remedial action schemes (RAS) and black start** — Generator RAS is used to restore and maintain power system frequency at acceptable levels. Black start service is obtained from suppliers that have the ability to self-start, energize lines, and provide start-up power to other generators thereby enabling timely restoration of electrical supply on the AIES in the event of a blackout. AESO payments for generator RAS and black start account  
15 for a minimal portion of the AESO's costs to procure ancillary services.

20 The AS Cost Study states that black start would be used to quickly restore loads that were on the system immediately prior to the outage and therefore hourly usage is the appropriate billing determinant. The AS Cost Study provides no conclusions on cost classification in respect of Generator RAS. Generator RAS and black start costs are currently recovered through energy multiplied by a percent of all-hours pool price, and the AESO proposes to continue this approach.

25 **Transmission Must Run (TMR)** — TMR is generation required by the AESO to be on-line and running at specific outputs in order to ensure system security. The AS Cost Study includes a detailed review of TMR costs, which — with the exception of Invitation to Bid on Credits (IBOC) contracts — are tied to a combination of hourly gas prices, pool prices, heat rate, and output. The study considers the mismatch between the AESO's costs to procure  
30 TMR, which are inversely proportional to pool price, and the AESO's current recovery of those costs, which is directly proportional to pool price. Consequently, the AS Cost Study recommends that although TMR costs can be classified as usage related, recovery as a percent of pool price is inappropriate as revenues would increase with pool price — the opposite effect of payments to TMR suppliers.

35 Conceptually, cost recovery of reactive power payments through a demand charge could be appropriate, such as that for Poplar Hill, but the AESO does not pay generators for reactive power dispatches. Consequently, the AESO proposes to recover TMR costs as a component of the voltage control charge, structured as a flat (non-varying) usage charge.

40 **Under-Frequency Mitigation** — If a contingency on the transmission system causes frequency to decline beyond what can be arrested through other actions, load is tripped off through a coordinated automatic under-frequency load shedding program. The AESO's payments to the under-frequency mitigation service providers are in the form of \$/MW amounts. Based on the \$/MW structure of payments, the AESO proposes to classify under-

frequency mitigation costs as 100% demand-related. This is a change from the current recovery of under-frequency mitigation costs as 100% varying usage (energy multiplied by a percent of all-hours pool price).

5     **Hydro Motoring** — Hydro motoring services are no longer purchased by the AESO.

10     **Poplar Hill** — The Poplar Hill generator provides TMR generation and voltage support to loads in northwestern Alberta. The AS Cost Study concludes that as payments for Poplar Hill services are fixed in nature, the current classification of Poplar Hill costs as 100% demand-related should be maintained.

15     **Interruptible load remedial action scheme (ILRAS)** — The AESO uses ILRAS to increase the import capability of the Alberta-BC interconnection. If the Alberta-BC tie trips concurrent with high import levels, ILRAS loads will automatically trip to limit frequency decline and prevent shedding of other load in Alberta. ILRAS has traditionally been considered a replacement for wires and classified accordingly, but the AS Cost Study notes that ILRAS may alternatively be considered to replace contingency reserves for imports and could accordingly be similarly classified, as usage-related.

20     The AS Cost Study concludes that the cost of ILRAS is relatively small, and that there are no material rate impacts regardless of how costs are allocated. The AESO therefore proposes the current classification in the same proportion as wires costs should be maintained, and proposes to classify the costs 46.6% to demand and 53.4% to flat usage.

25     The proposed ancillary services cost unbundling and related cost classification changes are provided in Table 4.3.1.

30     **Customer self-supply of ancillary services** — Customer self-supply is a component of the Wholesale Market Review currently underway. The AESO considers it prudent to wait for the outcome of this review and attendant legislation before setting out a proposal for customer self-supply of ancillary services. Consequently, the AESO seeks leave of the EUB to address customer self-supply of ancillary services at a future date.

Table 4.3.1 Proposed Ancillary Services Charges and Classification

Ancillary Service Component	Current Classification			Proposed Classification		
	MW	MWh	% of PP	MW	MWh	% of PP
<i>Operating Reserves Charge</i>						
Operating Reserves	-	-	100%	-	-	100%
Generator RAS	-	-	100%	-	-	100%
Black Start	-	-	100%	-	-	100%
<i>Voltage Control Charge</i>						
Transmission Must Run	-	-	<b>100%</b>	-	<b>100%</b>	-
<i>Other System Support Services Charge</i>						
Under Frequency Mitigation	-	-	<b>100%</b>	<b>100%</b>	-	-
Poplar Hill	100%	-	-	100%	-	-
ILRAS	<b>60%</b>	<b>40%</b>	-	<b>46.6%</b>	<b>53.4%</b>	-

Notes: MW indicates classification as demand  
MWh indicates classification as flat (non-varying) usage  
% of PP indicates classification as usage varying as percentage of pool price  
Changes in classification are indicated in **bold** in the table  
Classification of ILRAS changes to reflect the change in classification of wires costs  
The MWh component of ILRAS is recovered in the DTS rate schedule as part of the DTS Interconnection Charge, to avoid a small \$/MWh component in the OSS Services Charge

#### 4.4 Rate Design

Based on the cost allocation and classification outlined in Sections 4.1, 4.2, and 4.3, rate components for DTS and STS are calculated in Schedules 5.4 and 5.6 respectively. Schedule 5.7 provides the 2006 forecast billing determinants on which the rates are based.

Finally, Schedule 5.8 provides a comparison of the proposed changes by rate component, as compared to current interim rates (effective as of January 1, 2005).

Beyond the changes arising from the calculation of DTS and STS rate components to recover the 2006 revenue requirement, the structure of the AESO's rates remains generally unchanged. Other changes are discussed in the following sections, including the change to DTS billing capacity ratchet levels, Fort Nelson rate schedules, elimination of Demand Opportunity Service (1 Hour), Export Service and Import Service, the Primary Service Credit, and Losses Calibration Factor Rider E.

Given the above, the Board is prepared to accept that some portion of embedded wires costs are energy related. The Board also notes that preparing a cost of service study for transmission on a stand alone basis is a relatively new and unique process. The Board acknowledges the difficulties faced by Mr. Reimer in preparing his analysis and in the circumstances the Board considers the TCCS to be a good first step and is willing to accept its recommendations in the Board's approved rate design.

#### **5.4 Ancillary Services Cost of Service Study**

In response to Directions 10 and 11 of [Decision 2001-32](#), the AESO filed an Ancillary Services Cost of Service Study. The study was prepared by Mr. Randy Stubbings of Envision Consulting and was summarized at pages 11-15, Section 4 of the Application.

The AESO's proposed classification was summarized in Table 4.3.1 of the Application and is reproduced below.

The AESO explained the results of the study and their proposal as follows:<sup>39</sup>

Ancillary services costs to the AESO can also be viewed as a function of payments to ancillary service providers, and can be classified for rate design purposes as demand-related or usage-related. The costs could then be recovered through tariffs as fixed or variable charges, in accordance with the classification of the ancillary service payments. Basing rate design for ancillary services solely on alignment with payments to ancillary services providers may not always accord with the cost classification set out in the AS Cost Study, as cost causation is only one of several rate design criteria. In particular, the AESO is proposing ancillary services rates that also consider rate stability, simplicity of understanding, and economy of billing.

In Decision 2001-32, the EUB also noted "that the first step to self-provision [of ancillary services] is to unbundle the various system support services in the TA's tariff" (p. 41) and provided Direction 11 to "include rate proposals for unbundling SSS and proposals for customer self-supply of SSS" (p. 59). Based on the AS Cost Study and rate design considerations, the AESO proposes to unbundle certain ancillary services. The AESO recognizes that each of the many individual ancillary services (as detailed in the AS Cost Study) could be identified separately in the rate schedule, but considers such detailed unbundling would be premature and would unnecessarily complicate billing during the time that the market for such services is developing. For example, the AS Cost Study concludes that the cost of regulating reserves should be classified in accordance with customers' ranges of demand over a given period. Rates designed on this basis would degrade rate stability on an individual customer basis, and would also increase billing costs as extensive information system changes to the billing and metering systems would be required to support the resulting tariffs.

Accordingly, the AESO has unbundled ancillary services into three separate and distinct tariff charges categorized by separate cost recovery approaches:

- a) operating reserves charge, structured as a usage charge which varies as a percentage of pool price, averaged over all hours;
- b) voltage control charge, structured as a flat (non-varying) usage charge; and
- c) other system support services charge, structured as a demand charge.

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<sup>39</sup> Application, Section 4, pages 11-12

Table 4.3.1 Proposed Ancillary Services Charges and Classification

Ancillary Service Component	Current Classification			Proposed Classification		
	MW	MWh	% of PP	MW	MWh	% of PP
<b>Operating Reserves Charge</b>						
Operating Reserves	-	-	100%	-	-	100%
Generator RAS	-	-	100%	-	-	100%
Black Start	-	-	100%	-	-	100%
<b>Voltage Control Charge</b>						
Transmission Must Run	-	-	100%	-	100%	-
<b>Other System Support Services Charge</b>						
Under Frequency Mitigation	-	-	100%	100%	-	-
Poplar Hill	100%	-	-	100%	-	-
ILRAS (see note)	60%	40%	-	46.6%	53.4%	-

Notes: MW indicates classification as demand  
MWh indicates classification as flat (non-varying) usage  
% of PP indicates classification as usage varying as percentage of pool price  
Changes in classification are indicated in **bold** in the table  
Classification of ILRAS changes to reflect the change in classification of wires costs  
The MWh component of ILRAS is recovered in the DTS rate schedule as part of the DTS Interconnection Charge, to avoid a small \$/MWh component in the OSS Services Charge  
ILRAS Interruptible Load Remedial Action Scheme

### 5.4.1 Classification of Ancillary Services

The only party to submit any comments with respect to the AESO's proposal was FIRM. FIRM maintained that TMR costs should be allocated on a basis more reflective of cost causation and recommended that the AESO rate design for the TMR component of voltage control reflect the 1:2 ratio of TMR costs for DTS-MWH on-peak and off-peak charges. FIRM acknowledged such a muted price signal would not significantly affect customer consumption behavior but claimed it would better reflect cost causation.

In reply the AESO submitted that if a price signal is so muted that it will not affect customer behaviour, then there is little point in providing such a signal. If such a unique bill charge will vary by so little compared to an all-hours average charge and will seem illogical to many customers (as explained by Mr. Martin at T0657-58), then the AESO submitted there was no justification to warrant its implementation.

The Board agrees with the AESO and approves the recovery of TMR costs on a flat usage basis. Consistent with the Board's determinations with respect to classification of wires costs, the costs for ILRAS should be classified as 80% demand and 20% energy. The demand portion should be allocated on the same basis as the bulk wires.

## 5.5 Demand Transmission Service Rate Design

### 5.5.1 Unbundling

The AESO has stated that it considers the level of unbundling proposed in the Application to be adequate and any further steps in this regard should be deferred until the 2007 tariff. The AESO stated that it did not consider a bill containing seven to nine distinct charges to be simple.

Order 2006-315 released on December 15, 2006, which approved EPCOR's 2007 interim transmission facility owner tariff. The recorded cost was from AUC Decision 2008-125 released on December 3, 2008, which approved EPCOR's 2007-2009 transmission facility owner tariff on a final basis.

#### **Line 11 KEG Unit Transformers Conversion**

146 The 2008 recorded cost for the KEG unit transformers conversion was \$3.3 million. No corresponding amount was included in the approved forecast. The variance arose from directions in AUC Decision 2008-101 regarding AESO recovery of costs for Keephills-Ellerslie-Genesee ("KEG") conversion of unit transformers, released on October 21, 2008, as discussed in section 12 of this application.

#### **3.1.2 Ancillary Services**

147 The recorded ancillary service costs for 2008 totalled \$312.4 million, which is \$46.5 million (or 17%) more than the 2008 approved forecast of \$265.9 million. The primary component of this variance is an increase in active operating reserves costs of \$47.3 million (or 24%) due to more occurrences of high pool price periods and a trend of smaller discounts relative to pool price, and in some cases premiums, for operating reserves. The variance also includes an increase in standby operating reserves costs, a credit arising from trading fees and other related charges, and reductions in the costs of Brazeau fast ramp, under frequency mitigation, and interruptible load remedial action scheme ("ILRAS") services.

148 Explanations of the variances of the 2008 recorded costs from the 2008 approved forecast are provided in the sections that follow.

#### **Lines 17 to 26 Operating Reserves**

149 Operating reserves are unloaded megawatt capacity that is available to respond to temporary shortfalls in supply caused by the loss of a generating unit, intertie capabilities, or moment-to-moment fluctuations in the load. Operating reserves are comprised of regulating reserve and contingency reserves (including spinning and supplemental reserves).

150 Regulating reserve refers to the amount of synchronized generation that responds to automatic generation control ("AGC") signals that track moment-to-moment fluctuations in the supply and demand. Regulating reserves track variations in the load that cannot be met with energy dispatches. Because variations in supply and demand can be either positive or negative, regulating reserves have a range with an upper and lower limit. The volumes of regulating reserve are specified as a range in megawatts over which a level of control is required by the AGC system.

151 Spinning reserve is unloaded generation that is synchronized to the system, automatically responsive to deviations in frequency, and ready to serve additional demand following a System Controller directive within 10 minutes.

152 Supplemental reserve is unloaded generation, off-line generation, or system load that is ready to serve additional demand (generator) or to reduce demand (load) within 10 minutes of a directive from the System Controller.

153 Spinning and supplemental reserves are required in order to restore frequency following the loss of generation in Alberta or in the Western Electricity Coordinating Council (“WECC”) region. Alberta must comply with WECC policies for maintaining specific volumes of spinning and supplemental reserves in order to maintain reliability.

154 About 90% of operating reserves volumes are competitively procured through the Alberta Watt Exchange (“Watt-Ex”), an electronic exchange where transactions reflect bids and offers of the AESO and market participants. The remaining 10% of operating reserves volumes are procured directly from suppliers through Over-The-Counter (“OTC”) transactions.

*Lines 17 to 20 Active Operating Reserves*

155 Active operating reserves are the operating reserves that are forecast by the AESO as necessary to operate the Alberta Interconnected Electric System (“AIES”) securely and meet the AESO’s reliability obligations to WECC. 2008 recorded costs were \$244.1 million, which is \$47.3 million (or 24%) more than the 2008 approved forecast of \$196.8 million, and comprised the following amounts:

- For active regulating reserve, the 2008 recorded cost was \$70.3 million, which is \$14.7 million (or 26%) more than the 2008 approved forecast of \$55.7 million.
- For active spinning reserve, the 2008 recorded cost was \$94.7 million, which is \$20.1 million (or 27%) more than the 2008 approved forecast of \$74.6 million.
- For active supplemental reserve, the 2008 recorded cost was \$79.1 million, which is \$12.5 million (or 19%) more than the 2008 approved forecast of \$66.5 million.

156 The increase in 2008 recorded costs compared to the approved forecast for all active operating reserves primarily results from the competitive determination of price through the operating reserves market. Active operating reserves are generally reflective of pool price, and more high pool price periods occurred in 2008 compared to prior years on which the 2008 forecast was developed. As well, higher recorded costs reflected a trend of smaller discounts relative to pool price, and in some cases premiums, for operating reserves.

157 In total, 2008 recorded active operating reserves volumes were 5,614 GWh, which is 154 GWh (or 3%) less than the 2008 approved forecast of 5,768 GWh.

*Lines 21 to 24 Standby Operating Reserves*

158 Standby reserves are additional reserves that are available to the System Controller in the event an active provider fails to provide active reserves, or if actual requirements are higher than the active reserve forecast. Payments for standby reserves include a premium paid for the option to activate the standby reserves and a price that is paid if the reserves are activated.

159 For standby regulating reserves premiums, the 2008 recorded cost was \$7.4 million, which is \$2.7 million (or 57%) more than the 2008 approved forecast of \$4.7 million. For standby regulating reserves activations, the 2008 recorded cost was \$1.3 million, which is \$0.3 million (or 19%) less than the 2008 approved forecast of \$1.6 million.

- 160 For standby spinning reserves premiums, the 2008 recorded cost was \$4.9 million, which is \$1.3 million (or 36%) more than the 2008 approved forecast of \$3.6 million. For standby spinning reserves activations, the 2008 recorded cost was \$7.1 million which is \$3.1 million (or 78%) more than the 2008 approved forecast of \$4.0 million.
- 161 For standby supplemental reserves premiums, the 2008 recorded cost was \$1.9 million, which is \$0.5 million (or 36%) more than the 2008 approved forecast of \$1.4 million. For standby supplemental reserves activations, the 2008 recorded cost was \$3.0 million, which is \$0.1 million (or 3%) more than the 2008 approved forecast of \$2.9 million.
- 162 Standby reserves volumes are only about one to two percent of active reserves volumes. Both standby reserves volumes and activations are quite small, and therefore particularly sensitive to unforecastable real-time conditions, including variances from load forecasts as well as unplanned generation and transmission outages, which affect the availability of active reserves providers. The different standby reserves services may also occasionally be substituted for each other at the time of procurement and result in offsetting volume variances between the different services.
- 163 Standby reserves prices are determined by the various offer strategies of the numerous providers involved in the market at any given time. As for active reserves, the cost variances for standby reserves reflected more high pool price periods in 2008 and a trend of smaller discounts relative to pool price, and in some cases premiums, for operating reserves.
- 164 In total, 2008 recorded standby operating reserves volumes were generally consistent with the 2008 approved forecast.

*Line 25 Trading Fees and Other Related Charges*

- 165 The 2008 recorded cost for trading fees and other related charges was a credit of \$7.4 million. No corresponding amount was included in the approved forecast. The variance arose from unforecasted collections of non-compliance charges of \$8.1 million, offset by trading costs to Watt-Ex of \$0.7 million.

**Lines 27 to 35 Other Ancillary Services**

- 166 Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the AIES. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include Brazeau fast ramp, black start, transmission must run ("TMR"), under frequency mitigation, Poplar Hill, and interruptible load remedial action scheme ("ILRAS") services.
- 167 The 2008 recorded cost of other ancillary services was \$50.1 million, which is \$0.7 million (or 1%) less than the 2008 approved forecast of \$50.8 million, due to prices being lower than forecast for Brazeau fast ramp, under frequency mitigation, and ILRAS services.
- 168 Brazeau fast ramp (previously included with generator remedial action scheme ("GRAS")) service responds to a sudden loss of supply through the automatic and rapid adjustment of Brazeau generator operation. Brazeau fast ramp service stabilizes system frequency after a disturbance to avoid shedding firm load. The 2008 recorded cost of Brazeau fast ramp

service was \$0.1 million, which is \$0.6 million (or 83%) less than the 2008 approved forecast of \$0.7 million due to the expiry of the contract with the Brazeau fast ramp service provider during 2008.

- 169 Under frequency mitigation is configured to automatically trip a specific amount of load if the system frequency drops below 59.5 Hz following a system disturbance. The service is procured by the AESO through contracts with service providers. The 2008 recorded cost for under frequency mitigation was \$4.0 million, which is \$1.0 million (or 20%) less than the 2008 approved forecast of \$5.0 million due to contracted MW levels being lowered as a result of a change in operations at service providers' facilities.
- 170 ILRAS supports the import capability of the Alberta-BC interconnection. If the Alberta-BC interconnection trips concurrent with high levels of import, the system will become generation deficient, system frequency will decline, and the AESO will be required to shed load quickly in Alberta to arrest the frequency decline and maintain system reliability. The AESO contracts for loads to automatically trip in these situations to limit the frequency decline and attempt to prevent shedding of additional system load. The 2008 recorded cost for ILRAS service was \$0.009 million, which is \$0.8 million (or 99%) less than the 2008 approved forecast of \$0.8 million due to the continued provision of ILRAS under an early-2007 amendment to the service such that ILRAS is utilized only when the AIES is experiencing or expects an imminent supply shortfall.
- 171 The 2008 recorded costs for the remaining other ancillary services (black start, TMR, and Poplar Hill) did not vary significantly from the 2008 approved forecast.

### 3.1.3 Other Industry Costs

- 172 The 2008 recorded other industry costs were \$11.5 million, which is \$2.4 million (or 26%) more than the 2008 approved forecast of \$9.1 million, primarily due to the AESO's share of AUC overhead being higher than forecast offset by lower recorded external regulatory costs.

### Line 37 External Regulatory Costs

- 173 External regulatory costs include cost recovery amounts related to the AESO's regulatory proceedings. The staff, legal, and consulting costs in the administrative costs section of the AESO's revenue requirement do not include AESO recoverable regulatory costs.
- 174 The 2008 recorded external regulatory costs were \$0.8 million, which is \$3.3 million (81%) less than the 2008 approved forecast of \$4.1 million. In 2008, recorded external regulatory costs represented the recoverable costs of the AESO and registered participants related to the AESO's 2007 general tariff application and Ancillary Services Article 11 negotiated settlement proceedings. The 2008 forecast amount had been based on the estimated cost recovery for several AESO proceedings which did not result in cost awards in 2008, including:
- the AESO's next general tariff application, now planned to be filed in the third quarter of 2009;
  - 2006 and 2007 deferral account reconciliations, incorporated into the 2004-2007 deferral account reconciliation application filed on June 2, 2008;
  - recovery of costs for the KEG conversion of unit transformers, filed on April 14, 2008;