

**Title:** 2003 Illustrative Example – July 2003; pages 79-84 of 192 from Appendix K

**Preamble:** Explanations for costs and Rider C, Page 4 of 27

**Reference:** Technical Meeting Materials, February 8, 2008

**Request:**

- (a) The total industry costs for the month of July 2003 are shown by rate component of Interconnection Charge, Operating Reserve Charge and Other System Support Charges. Please describe and explain the derivation of the monthly costs by rate component from the actual monthly costs that would have been received and paid by the AESO by revenue requirement component such as wires costs, ancillary services costs, voltage control, under frequency, etc.
- (b) The actual revenue and costs are provided by overall rate component but not by the components of the rate structure that are demand and energy related. Please discuss and quantify the impact of utilizing demand and energy sub-components as a further breakdown of interconnection charges in developing a more accurate deferral account reconciliation.
- (c) In column D the 2003 Rider C actual refund is shown on a monthly basis as a total for each DTS customer rather than a monthly amount assigned to each rate component? Please discuss and quantify the impact of assigning monthly Rider C amounts to each rate component and further to the demand and energy sub-components.
- (d) To help appreciate the drivers of the deferrals for 2003 please provide by month, the energy supplied, energy consumed, average pool price, demand in MW-Months and regulated supply in MW-Months on a forecast basis and actual basis.

**Response:**

- (a) All revenue requirement component costs are allocated to rate components in accordance with the rate calculations filed by the AESO (or its predecessors) and approved to be effective for the production months to which the costs relate. For example, for July 2003, revenue requirement component costs were allocated as follows.
  - (i) Wires, other industry, and general and administrative (TA) costs were allocated 58% to DTS interconnection charge and 42% to STS interconnection charge.
  - (ii) Operating reserves, generator remedial action schemes (RAS), black start, transmission must-run (TMR), under frequency mitigation, hydro motoring, and Fort Saskatchewan load shed costs were allocated 50% to DTS operating reserve charge and 50% to STS operating reserve charge.

- (iii) Poplar Hill costs were allocated 100% to DTS other system support services charge.
  - (iv) Interruptible load remedial action scheme (ILRAS) costs were allocated 40% to DTS interconnection charge and 60% to DTS other system support services charge.
  - (v) Losses costs were allocated 100% to STS losses charge.
- (b) Interconnection charge deferral account balances are allocated to customers based on customers' interconnection charge revenue. Therefore, using demand and energy sub-components would have no material impact on the accuracy of the allocation.

Consider an example where interconnection charge deferral account balances represent 5% of recorded interconnection charge revenue. If demand and energy sub-components were used, the deferral account balance would be classified in the same manner as the original forecast interconnection charge revenue requirement — as 60% demand-related and 40% energy-related, assuming the 2003 allocation was approved to be in effect at the time. The deferral account balance would therefore represent 5% of demand-related revenue and 5% of energy-related revenue. Since the demand and energy sub-components would always increase by the same amount (assuming the classification factors would not change), the same result is achieved when the deferral account balance is allocated on total interconnection charge revenue. In the example, each customer would receive an allocation of the deferral account balances representing 5% of their interconnection charges revenue.

The only case where using demand and energy sub-components might produce a different result would be when a cost component is allocated to only one sub-component of a charge. The only instance of this in the AESO's rates is the allocation of 40% of interruptible load remedial action scheme (ILRAS) costs to the energy sub-component of the DTS interconnection charge. However, 40% of ILRAS costs represents only about 0.05% of the AESO's annual revenue requirement. A more detailed allocation of ILRAS deferral account balances would therefore not result in a material impact on the total deferral account amounts allocated to customers.

- (c) During 2003, Rider C was determined by rate only, in accordance with the structure of Rider C in the AESO's tariff approved by the EUB at the time. To allow the deferral account reconciliation for 2003 to be presented in the same format as for 2004 and 2005, the 2003 Rider C amounts were allocated to rate components (interconnection charge, losses charge, operating reserve charge, and other system support services charge) based on the customer's current deferral account balance allocation refund or charge provided in Column B of the referenced tables.

However, allocating or assigning Rider C amounts to rate components and sub-components has no impact on the final deferral account charges or refunds to individual customers. All Rider C charges are effectively "unwound" in the deferral account reconciliation and allocation.

As discussed in section 7.1 of the application, deferral account balances are allocated to customers based on each customer's "base rate" revenue by rate and rate component. This determines a deferral account balance attributed to each customer. Rider C

charges and credits already collected from or refunded to the customer are then applied against the customer's deferral account balance. This process results in a net deferral account amount remaining to be charged to or collected from the customer. Those amounts are detailed in the Appendices to the application.

As the deferral account balances are allocated to customers before the application of Rider C against the deferral account balances, applying Rider C by rate component and sub-component would not affect the net amount remaining to be charged or collected.

- (d) Please refer to attached Schedule ASBG-PGA.AESO-001 (d) for the requested monthly forecast and actual billing determinants for 2003.

**Title:** 2003 Illustrative Example – Annual 2003; pages 4 - 8 of 192 from Appendix K

**Preamble:** The 2004 Rider C amount is shown by rate component and a %age amount is shown as related to 2003, Page 6 of 27.

**Reference:** Technical Meeting Materials, February 8, 2008

**Request:**

- (a) Please discuss the derivation of the 2004 Rider C by rate component as contrasted to the 2003 Rider C.
- (b) Please provide the supporting details for the determination of these 2003 related % ages and a discussion of the derivation.

**Response:**

- (a) Prior to 2004, Rider C was determined by rate only and as a percentage increase or decrease (rather than a \$/MWh amount). That is, each quarter a percentage increase or decrease was determined and applied to Demand Transmission Service (DTS) and Supply Transmission Service (STS) charges such that the DTS and STS deferral account balances would be restored to zero over the following quarter.

Effective January 1, 2004, in response to direction in EUB Decision 2003-099 on the AESO's 2000-2002 Deferral Account Reconciliation, Rider C was determined as a \$/MWh charge or credit by rate component (interconnection charge, losses charge, operating reserve charge, and other system support services charge). The AESO understands that the refinement of Rider C, from differentiation by rate only to differentiation by both rate and rate component, was implemented to improve the accuracy of Rider C and to minimize the need for redistribution of deferral account balances between customers at the time of a retrospective reconciliation.

Although the derivation of Rider C changed in 2004 compared to 2003, there is no impact on the filed deferral account reconciliations as Rider C charges and credits are effectively "unwound" as discussed in Information Response ASBC-PGA.AESO-001 (c).

- (b) Rider C in the first quarter of a year addresses any forecasted carry-forward variance at the end of the prior year and the forecasted variance for the first quarter of the current year. As a portion of the Rider C amounts in the first quarter relate to the prior year, the AESO determines an allocation percentage that is applied to the first quarter collections or refunds to associate the appropriate portion to the prior year. If required, a portion of second quarter Rider C amounts may similarly be applied back to the prior year as occurred for Rider C in the second quarter of 2005.

In Column G of the referenced tables, the allocation percentages that were applied to the Q1 2004 Rider C amounts were determined by the AESO to settle the carry-forward variance at the end of 2003. The values simply reflect the year-end carry-forward variance, by rate and rate component, as a percentage of the Rider C collections or refunds in the first quarter of 2004, also by rate and rate component. The values were determined at the time of the 2003 deferral account reconciliation such that the net deferral account balance for 2003 was zero after application of Rider C, as shown in Table 2-3 on page 15 in section 2.3 of the Application.

**Title:** Other revenue collected

**Preamble:** 2005, 2004 and 2003 allocations

**Reference:** Appendix F, Other Revenue Detail

**Request:**

- (a) Please provide the payment of COS credits for each month of 2005, 2004 and 2003 to each DTS customer.
- (b) Please discuss whether the COS payments to each DTS customer should be assigned on a customer basis in the deferral account reconciliation.
- (c) Please discuss whether any of the other revenue categories should be assigned to specific DTS or STS customers rather than the overall DTS and STS classes. Please quantify the potential impact of specific assignment of these cost categories.

**Response:**

- (a) Please see attached Schedules ASBG-PGA.AESO-003 (a)-A, -B, and -C which provide COS Credits by month by customer for 2003, 2004, and 2005 respectively. Customers are identified only by number in each year to maintain confidentiality of customer-specific data, and customers do not necessarily occur in the same position in the tables for all three years.
- (b) No, Customer-Owned Substation (COS) Credits should not be assigned to customers in the deferral account reconciliation.

The COS Credit is not subject to deferral account treatment in the AESO's approved tariff. The only rates to which the 2003, 2004, and 2005 deferral accounts apply are Rates DTS and STS, as noted on the rate sheets for those rates and for Riders B and C. The AESO considers that applying deferral account treatment "after the fact" to other than Rates DTS and STS would constitute a retroactive change to an approved tariff and would be inappropriate.

The AESO believes it is appropriate that the COS credit is not subject to deferral account treatment because the COS Credit represents average costs that are effectively avoided by TFOs when customers install their own substations. As such, there can be no meaningful way to determine the variance between forecast and actual costs, which is what makes up the deferral account balance.

- (c) No, none of the other revenue categories should be assigned to specific customers either. As noted in part (b) above, the only rates to which the 2003, 2004, and 2005

deferral accounts apply are Rates DTS and STS, and it would be inappropriate to apply deferral account treatment “after the fact” to other than Rates DTS and STS.

In particular, most of the other revenue categories in Appendix F relate to AESO opportunity services: Demand Opportunity Services (DOS 7 Minutes, DOS 1 Hour, and DOS Term), Export Service (ES), and Import Service (IS). Opportunity services are provided on an as-available basis to customers who use such services based on short-term economic choices. Opportunity services typically exhibit characteristics of price certainty, simplicity of understanding, and cost-effective administration. Applying deferral account treatment to opportunity services would remove the price certainty needed for such rates to be effective and would be inconsistent with the basis for such rates.

Under-Frequency Load Shedding (UFLS) Credits should not be subject to deferral account treatment for reasons similar to those provided in part (b) above for COS Credits. The UFLS Credit is assessed based on the relay trip setting level, and actual costs cannot be determined for it.

Regulated Generation Unit Connection Costs (RGUCC) charges were established in Decision U97065 and 2000-1 of the Alberta Energy and Utilities Board (EUB) to recover a deemed amount representative of generation connection costs for previously-regulated generators. There is no meaningful way to determine the variance between forecast and actual costs, which is what makes up the deferral account balance.

The “STS Annual Operation and Improvement Charge” identified in the other revenue report is comprised of the “Other Expenses Charge” amounts received under the AESO’s Duplication Avoidance Adjustment Riders. The Other Expenses Charge represents forecast expenses for operation and maintenance, capital improvements, and property tax that the Duplication Avoidance Tariff (DAT) customers would have incurred had they actually built the duplicate facilities. However, those facilities were never built and there can be no actual costs determined for them. Again, there is no meaningful way to determine the variance between forecast and actual costs, which is what makes up the deferral account balance.

As there is no basis to establish a deferral account balance for the above amounts, it is not possible to quantify the potential impact of specific assignment of these costs.

Interest income, foreign exchange gains and losses, and miscellaneous income do not relate to specific customers, and therefore cannot be assigned to specific customers in the deferral account reconciliation.



**Title:** Forecast and actual billing determinants

**Reference:** Appendices I and J

**Request:**

For 2005 and 2004 please provide by month, the energy supplied, energy consumed, average pool price, demand in MW-Months and regulated supply in MW-Months on a forecast basis and actual basis.

**Response:**

Please see attached Schedules ASBG-PGA.AESO-004-A and -004-B for the requested monthly forecast and actual billing determinants for 2004 and 2005, respectively.

**Title:** 2005 Revenue Requirement and Recorded Costs

**Preamble:** Variance explanations

**Reference:** Application, page 20 of 79

**Request:**

- (a) For active reserves, lines 18-20, please provide reasons for the substantive increases over forecast and the mitigation measures, if any, that were employed in 2006 and 2007 to reduce potential variances.
- (b) Please compare the 2005 active reserves variances with the historical variances for 2003 and 2004.
- (c) For the TMR variance, line 30, please discuss the amount of disputed payments in 2005, if any.
- (d) Does the recent Article 11/24 negotiated settlement impact any of the 2005 amounts; please provide details.
- (e) For Board Member fees, line 48, please provide the number of Board members and the fees per member and the reason for the variance. Has there been a change in the number of Board members for 2006 and 2007.
- (f) For legal, line 50, please provide reasons for the variance. Do these costs represent internal or external costs. Does the AESO now have internal legal counsel.

**Response:**

- (a) As explained on page 24 of section 3.1.2 of the Application, "The increase in 2005 recorded costs compared to the approved forecast for all active operating reserves was due to a large increase in operating costs observed in the second half of 2005 as a result of pool price increases." Schedule ASBG-PGA.AESO-004-B, provided in response to Information Request ASBG-PGA.AESO-004, shows an average recorded pool price of \$95.09/MWh for July to December 2005, which is \$36.77/MWh (or 63%) more than the average forecast pool price of \$58.33/MWh for the same period.

The AESO procures active operating reserves in accordance with its reliability obligations to the Western Electricity Coordinating Council (WECC). The operating reserve requirement depends on Alberta's firm load responsibility and the proportions of hydro, wind, and thermal generation serving load.

Operating reserves are purchased from the ancillary services market exchange and through over-the-counter contracts. All operating reserve providers are paid their

accepted offer price for the ability of the AESO to utilize their energy as reserves. The majority of operating reserve offer prices is indexed to the pool price. As noted above, the increase in pool price compared to the forecast for 2005 resulting in active operating reserve costs being above forecast for 2005.

The AESO utilizes a competitive procurement process for ancillary services that provides transparency as well as a dispute resolution mechanism. The AESO regularly reviews its processes, standards, and rules to ensure that they are consistent with a fair, efficient, and openly competitive market and provide appropriate compensation for commitment of generating units for reliability purposes.

- (b) As discussed in part (a) above, the cost of active operating reserves depends on volumes and pool price. Please refer to attached Schedule ASBG-PGA.AESO-005 (b) attached for a comparison of variances for active operating reserve volumes, average pool price, and active operating reserve costs for 2003, 2004, and 2005.
- (c) The Alberta Utilities Commission issued Decision 2008-014 approving the AESO's Ancillary Services Article 11 Negotiated Settlement on February 12, 2008. That decision finalized for rate-making purposes all costs incurred by the AESO for conscripted TMR service for the period December 17, 2004 until February 12, 2008, inclusive, except for conscripted TMR services from the Rainbow Lake facilities which remain interim and are subject to further adjustment under the decision.

The AESO expects that on the order of \$2 million of adjustments relating to the Rainbow Lake facilities will occur in early 2008 and will be included in the AESO's 2007 deferral account application, currently expected to be filed as an extension of this application as noted above. None of those adjustments are expected to relate to 2005. The AESO therefore considers that no TMR payments remain disputed with respect to 2005.

- (d) Please refer to Information Response Comm.AESO-001 (d).
- (e) While the number of AESO Board Members may change during a year due to new appointments and retirements, the AESO Board complement at the beginning of each calendar year from 2005 to 2007 was as follows:
- 2005: 8
  - 2006: 8
  - 2007: 4

The fees received by individual AESO Board Members are considered confidential information and are not disclosed. In 2005, the total recorded Board fees were \$0.4 million, which is \$0.1 million (or 40%) greater than the approved forecast of \$0.3 million due to additional involvement of the Board with the AESO's corporate reorganization during 2005.

- (f) In 2005, recorded legal costs were \$0.6 million, which is \$0.2 million (or 54%) greater than the 2005 approved forecast of \$0.4 million due to unanticipated costs related to the AESO's participation in the British Columbia Transmission Corporation Open Access Tariff.

The AESO has always included legal counsel in its staff complement. The AESO supplements internal legal counsel resources by external resources to allow increased

flexibility to meet workload demands, increased access to specialized skills and expertise, continuous improvements in quality, and additional objectivity, as discussed in section 8.6 of the AESO's 2007 General Tariff Application filed on November 3, 2006. The costs included as "Legal" on Line 50 of Table 3-1 include both internal and external legal costs, but do not include legal costs which are recoverable as part of a regulatory proceeding. Such recoverable legal costs are included as "External Regulatory Costs" on Line 41 of Table 3-1.

**Preamble:** At page 4 the AESO indicates that this is the first reconciliation for 2004 and 2005 and the second reconciliation for 2003. At page 6 the AESO indicates that it has also included adjustments for the years 1999-2002.

**Reference:** Application, pages 4 and 6

**Request:**

- (a) Does the AESO consider that the applied for adjustments to the 1999-2002 periods will finalize these periods?
- (b) If the response to (a) is no, please specify the expected remaining items, the expected quantum of those items, the number of reconciliations being contemplated, and the timing for finalization of each of those items.
- (c) Does the AESO consider that further reconciliations will be necessary for the 2003-2005 periods?
- (d) If the response to (d) is yes, please specify the expected remaining items, the expected quantum of those items, and the timing for finalization of those items.
- (e) Please explain the principal causes for the periods that are the subject of this application remaining unfinalized for this period of time.

**Response:**

- (a) No, the AESO does not consider that the applied-for adjustments finalize the 1999-2002 deferral account periods.
- (b) The AESO is currently aware of about \$8 million in adjustments originating in metered volume restatements that will reduce the cost of losses in the years 2001 to 2005. The billing process that would collect these amounts from energy market participants and accordingly reduce the cost of transmission line losses has been suspended as a result of direction received by the AESO from the Alberta Department of Energy (DOE). Based on recent discussions with the DOE, the AESO currently understands that a resolution of the outstanding adjustments will occur in 2008. If the adjustments occur prior to the data cut-off date for the AESO's 2007 deferral account reconciliation, they will be included in the AESO's 2007 deferral account application, currently expected to be filed as an extension of this application in May 2008 (as discussed in the cover letter accompanying these information responses). If the adjustments occur after the data cut-off date for the 2007 reconciliation, they will be included in the AESO's 2008 deferral account reconciliation application, currently expected to be filed in early 2009.

The AESO is not aware of any other material adjustments that specifically relate to the deferral account periods 1999-2002.

- (c) Yes, the AESO considers that further reconciliation will be necessary for the 2003-2005 deferral account periods.
- (d) As explained in the AESO's response to Question 6 from the Technical Meeting held on February 8, 2008, about \$11.5 million of adjustments relating to the periods 2003-2005 have arisen from EUB decisions for ATCO Electric issued in 2007. These adjustments include:
- a \$13.0 million refund from ATCO Electric with respect to ATCO Electric's tax liability refiled addressed in EUB Decision 2007-104, and
  - a \$1.5 million charge to the AESO with respect to ATCO Electric's 2005 deferral account addressed in EUB Decision 2007-071.

The adjustments were recorded by the AESO on December 31, 2007, and will therefore be included in the AESO's 2007 deferral account application, currently expected to be filed as an extension of this application.

The adjustments discussed in part (b) above also affect the periods 2003-2005. As described in part (b), depending on the timing of the adjustments the AESO will include them in either its 2007 or 2008 deferral account reconciliation application.

Finally, Decision 2008-014 approving the AESO's Ancillary Services Article 11 Negotiated Settlement will result in costs for unforeseen TMR services paid on an interim basis as far back as December 17, 2004 being reassessed under the pricing provision approved in the decision. The AESO expects that on the order of \$2 million of adjustments relating to these costs will occur in 2008 after the data cut-off date for the AESO's 2007 deferral account reconciliation. The costs will therefore be included in the AESO's 2008 deferral account reconciliation application, currently expected to be filed in early 2009.

As well, Decision 2008-014 ordered that costs incurred by the AESO for conscripted TMR services from the Rainbow Lake facilities remain interim and are subject to further adjustment under the decision. The AESO expects that on the order of \$2 million of adjustments relating to these costs will occur in early 2008 and will be included in the AESO's 2007 deferral account application, currently expected to be filed as an extension of this application as noted above.

The AESO is not aware of any other material adjustments that specifically relate to the deferral account periods 2003-2005.

- (e) There appear to be two main causes of adjustments which may arise in respect of periods occurring several years earlier:
- (i) *Regulatory decisions* — These may:
- cause historical utility practice to be revisited, such as Decision 2007-104 regarding ATCO Electric tax liability;
  - finalize costs previously approved on an interim basis, such as Decision 2008-014 regarding the AESO's ancillary services costs for the period December 17, 2004 until February 12, 2008; or
  - settle cost for TFO deferral accounts, such as Decision 2007-071 regarding ATCO Electric's 2005 deferral account.

It appears that decisions changing historical utility practices or finalizing interim costs that affect periods occurring several years earlier are relatively uncommon. However, decisions settling TFO deferral accounts are expected to occur regularly, and could frequently affect periods occurring two or three years earlier, especially given that a TFO deferral account is subject to a regulatory process before a decision is rendered, which then results in the AESO receiving an adjustment relating to the deferral account.

- (ii) *Restatement of meter volumes over multiple years* — As explained in Information Response TCE.AESO-002, audit and process enhancements for revenue class meters have reduced the likelihood of extended period data restatements. As well, variances between costs and revenues for losses are now handled through a prospective process in Calibration Factor Rider E rather than through retrospective reconciliation for Deferral Account Adjustment Riders B and C. The losses adjustments discussed in part (b) above would therefore not affect deferral account reconciliations for 2006 and later years.

**Title:** Time Limit for Adjustments

**Preamble:** In Decision 2006-042 the Energy and Utilities Board (EUB or the Board) imposed a two year limitation period on adjustments to Deferred Gas Accounts (DGA).

**Request:**

- (a) Does the AESO consider there to be merit in imposing a limitation period on adjustments to its deferral accounts in the interest of finality and certainty?
- (b) If the Commission ultimately considers a limitation should be applied, please discuss the length of the limitation period that the AESO would consider reasonable, and the circumstances in which any such period should be applied to the AESO.
- (c) Please discuss whether, and to what extent, the criteria stated in Decision 2006-042 should be applied by the Commission in this case.

**Response:**

- (a) The AESO does not consider that a limitation period can or should generally be imposed on adjustments to its deferral accounts.

The AESO is a statutory not-for-profit corporation, is independent of any industry affiliations, and owns no transmission or market assets. It was created by the *Electric Utilities Act*, which states in section 14(3):

*The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation.*

As a not-for-profit entity, the AESO has no shareholder, as such. The AESO generates no return nor has any equity component of a capital structure which could accommodate adjustments. The AESO therefore concludes that all prudently-incurred adjustments to its costs and revenues must be subject to deferral account treatment without limitation.

However, it may be possible to exclude certain prior-period adjustments from the AESO's deferral accounts by limiting, in time, the extent to which the AESO could be affected by such adjustments, whether positive or negative. For example, if regulatory decisions such as those discussed in Information Response Comm.AESO-001 (d-e) required adjustments only within limited periods, adjustments prior to those periods would not need to be addressed in the AESO's deferral account.

- (b) As discussed in part (a) above, the AESO does not consider that a limitation period can or should generally be imposed on adjustments to its deferral accounts. However, it may be possible to impose a limitation on the extent of retrospective reconciliation of adjustments to the AESO's deferral accounts.

Most utilities recover prior-period deferral account adjustments by carrying them forward and recovering them from customers in the next succeeding period, frequently referred to as prospective recovery. However, the AESO reconciles its deferral accounts retrospectively, and recovers them based on the actual billing determinants that existed in the period to which the adjustment relates. The first decision of the Alberta Energy and Utilities Board (EUB) approving retrospective reconciliation of deferral accounts by the AESO was Decision 2003-054 on the Engage Energy Article 24 Refund. Retrospective recovery has been confirmed in subsequent EUB decisions on AESO deferral account reconciliations.

Stakeholders also generally supported retrospective reconciliation for all deferral account adjustments during stakeholder consultation conducted by the AESO from November 2004 through December 2005, as discussed in Appendix A to the AESO's application. Stakeholders considered that retrospective reconciliation provided the most accurate deferral account reconciliation and allocation, and they accordingly supported multiple reconciliations of deferral accounts to address material adjustments. The AESO committed to completing three annual reconciliations for a deferral account year and suggested the process be further reviewed after a third reconciliation was completed for the first time.

Notwithstanding, a limitation on the use of retrospective reconciliation would allow finality and certainty of prior-period charges, while still allowing for fair and reasonable allocation of many of the deferral account amounts under consideration. For example, it may be reasonable to limit the retrospective reconciliation period for adjustments which are expected to occur with regularity, such as those arising from TFO deferral account settlements as discussed in Information Response Comm.AESO-001 (e).

- (c) In Decision 2006-042, the EUB addressed a limitation period for adjustments to deferred gas accounts for ATCO Gas, Direct Energy Regulated Services, and AltaGas Utilities. The decision primarily contemplated a limitation period such that adjustments which extended beyond such period would not be subject to deferral account treatment but would instead accrue to the utility's return to shareholders. For the reasons stated in part (a) above, the AESO considers that the majority of the criteria stated in Decision 2006-042 are not applicable to the AESO due to its legislated not-for-profit status. However, as noted in part (b), it may be reasonable to instead limit the extent of retrospective reconciliation required.

The AESO offers the following additional comments on specific principles discussed in Decision 2006-042:

- The AESO's revenue meters are subject to the *Electricity and Gas Inspection Act* and in as much as the EUB did not intend to make any decision that would conflict with that Act, such intent would also apply to the AESO.
- The AESO does not have a shareholder, earns no return and has no equity component of a capital structure, and, accordingly, consideration of inappropriate incentives and effects on utility risk would generally not apply to the AESO.
- The *Regulated Default Supply Regulation* and the *Regulated Rate Option Regulation* do not apply to the AESO.
- Intergenerational equity questions do not arise with the AESO's retrospective deferral account reconciliation, as adjustments are attributed back to customers that existed in the periods to which the adjustments relate.

**Preamble:** In the above settlement agreement and decision, the AUC approved a methodology for determining TMR payments. The AESO also indicated that it was close to finalizing a contract with ATCO Power (AP) for services provided by AP but not covered by the settlement.

**Reference:** Article 11 Negotiated Settlement Agreement, Decision 2008- 014

**Request:**

- (a) Please confirm that all interim payments made to parties, including AP, for the periods covered by the reconciliation periods that are the subject of this application, have already been included in the financial records of the AESO and the reconciliations filed.
- (b) Please confirm that it is only the incremental payments due to parties, as a result of the settlement or contract in the case of AP, that need to be charged to the AESO's financial records.
- (c) Please identify the reconciliation periods that these payments fall into and the timing for filing of applications to approve such reconciliations.

**Response:**

- (a) Confirmed.
- (b) Confirmed.
- (c) Please refer to Information Response Comm.AESO-001 (d).



**Preamble:** Timing of Deferral Account Reconciliation

**Request:**

Does the AESO plan to put forth a proposal for process improvement to ensure that in the future, unreasonable delays from deferral account reconciliations may be mitigated?

**Response:**

Please refer to Information Responses TCE.AESO-007 and TCE.AESO-008.

**Title:** Material Amounts Occurring After the Cut Off Date

**Preamble:** At the technical session, the AESO identified a refund amount of about \$25.0 million related to ATCO Electric's income tax that was identified after the August 31 cut off date. While Riders B and C provide mechanisms to recover cash flow shortfalls; there does not appear to be any corresponding mechanism to refund excess cash on a timely basis.

**Reference:** Technical Session Held February 8, 2008

**Request:**

Is the AESO prepared to propose any procedural changes that would result in known material amounts identified after the cut off date being reflected in deferral accounts and passed through to customers without delay?

**Response:**

Please refer to Information Responses TCE.AESO-007 and TCE.AESO-008.



**Title:** Visibility of Details on Deferral Accounts to Discos

**Preamble:** PICA wishes to know how much detail with respect to the AESO deferral account adjustments would be visible to Discos when they attempt to pass through the changes to their customers

**Reference:** Technical Session Held February 8, 2008

**Request:**

- (a) The AESO has determined the deferral accounts by rate class and rate category. Please indicate the level of detail from the AESO that would be available to Discos (account level by component, POD level by component) when they prepare their respective applications to flow through the changes resulting from this application.
- (b) Please indicate the years for which the above details would be available.

**Response:**

- (a-b) Subsequent to filing the application, the AESO has made available to all customers, including Distribution Facility Owners (DFOs), the customer-specific settlement point data by rate and rate component to support the appendices in the application for the years 2003 to 2005.

**Preamble:** In its application in the appendices, the AESO has filed information for each customer by year and by month. By separate request the AESO has provided revenue information for TransAlta by settlement point for each year and month.

**Request:**

- (a) Please confirm that information provided to date in this application does not allow a customer to calculate the deferral account refund (charge) by settlement point. If (a) cannot be confirmed, please indicate where in the application the information can be located to calculate the deferral account refund (charge) by settlement point.
- (b) Please confirm that the AESO will not be providing the calculation of the deferral account refund (charge) by settlement point similar to the calculations in Appendix H provided by customer. If (b) cannot be confirmed, please indicate when the calculation of the deferral account refund (charge) by settlement point will be provided.
- (c) If (a) and/or (b) are confirmed, please confirm that the information required to do the calculations of the deferral account refund (charge) for each customer settlement point will be provided to those customers that request it.
- (d) Please confirm that calculating the deferral account refund (charge) by company and allocating back to each settlement point provides the same information for each settlement point and total company as performing the deferral account refund (charge) calculations at each settlement point and summing to obtain the total company.
- (e) Please confirm that the appendices of the application that are currently provided only in Adobe Acrobat format will be made available in Microsoft Excel.

**Response:**

- (a) Confirmed. The presentation of the information in the application was at the customer level, similar to previous applications, as opposed to at the settlement point level. Subsequent to filing the application in December 2007, the AESO has made available to all customers all of the relevant settlement point data that was not included in the application.
- (b) Not confirmed. Please refer to part (a) above.
- (c) Confirmed. Please refer to part (a) above.
- (d) Confirmed.

(e) Not confirmed.

The settlement point information provided by the AESO subsequent to filing the application in December was in Microsoft Excel format. For subsequent applications, customers will be provided all settlement point data in Microsoft Excel or comma separated values (csv) file format.

The customer allocation detail in the appendices that are filed with the Alberta Utilities Commission will only be available in Adobe Portable Document Format (PDF) due to the significant amount of manual editing that would be required to provide this information in Microsoft Excel format.

**Preamble:** At page 45, Table 4-4, line 6 of the Application, the AESO indicates a Rider C refund of \$7.7 million for the losses charge in 2004 as well as a deferral account under-collection balance of \$3.8 million for the same period.

At page 46, lines 22 to 25 of the Application, the AESO states:

As explained in sections 4.1 and 4.2, loss costs and revenues varied from forecast due to a combination of higher volumes in low pool price hours and lower volumes in high price hours as compared to forecast. Recorded losses volumes were also somewhat less than forecast for 2004.

**Reference:** Application - Section 4 - 2004 Financial Results and Deferral Account Balance, page 45, Table 4-4.

Application - Section 4 - 2004 Financial Results and Deferral Account Balance, page 46, Lines 22 - 25.

**Request:**

- (a) Please explain in greater detail the effect of a combination of higher volumes in low pool price hours and lower volumes in high price hours as compared to forecast, including examples.
- (b) Are the circumstances described in (a) the only reasons for differences between forecast and actual costs in the 2004 deferral account balances? If no, please provide details of the other reasons.
- (c) Please explain how the circumstances described in (a) influence Rider C to be calculated incorrectly (i.e. a Rider C refund of \$7.7 million for the losses charge in 2004 coinciding with a deferral account under-collection balance of \$3.8 million).

**Response:**

- (a) The cost of losses is forecast based on pool price and losses volumes, estimated using forecast load and generator-specific dispatch patterns. Depending on actual generator dispatch (which depends in part on pool price), as well as actual load, losses volumes in any specific hour will vary from forecast. Actual pool price will also vary from forecast. The impact of higher volumes in low pool price hours and lower volumes in high pool price hours is illustrated in the following simplified two-hour example.

Hour	Pool Price \$/MWh	Forecast Losses		Recorded Losses	
		Volume MWh	Cost \$	Volume MWh	Cost \$
Hour A	\$40.00	300	\$12,000	400	\$16,000
Hour B	\$60.00	400	\$24,000	300	\$18,000
Total	—	700	\$36,000	700	\$34,000

In the example, the only difference between the forecast and recorded values is that recorded volume is higher in the lower pool price hour and lower in the higher pool price hour. As a result, although total recorded losses volume remain the same as forecast, total recorded losses cost is lower than forecast.

Losses revenue similarly depends on hourly generator volumes and hourly pool price, as well as on generator-specific loss factors. Recorded revenue will similarly vary from forecast when recorded volumes are higher in low pool price hours and lower in high pool price hours, compared to forecast. Recorded revenue will also vary from forecast when actual generator dispatch varies from forecast dispatch patterns, as a result of the generator-specific loss factors.

- (b) Total recorded losses volume for 2004 was 2,862 GWh, which is 11 GWh (or 0.4%) less than the 2004 forecast losses volume of 2,873 GWh. Average recorded pool price for 2004 was \$56.21/MWh, which is \$2.17/MWh (or 4%) higher than the 2004 forecast pool price of \$54.05/MWh. Total recorded STS generator volumes for 2004 were 52,875 GWh, which were 1,725 GWh (or 4%) less than the forecast STS volumes of 54,600 GWh.

Recorded volumes being somewhat less than forecast and recorded pool price being somewhat higher than forecast would both contribute to variances between forecast and actual losses costs and revenue, and therefore to the losses deferral account balance. However, the primary reason for the recorded costs and revenues both being less than forecast was the combination of higher volumes in low pool price hours and lower volumes in high price hours, compared to forecast.

- (c) The circumstances described in part (a) above result in variances from forecast for both cost of losses and losses revenue, but do not necessarily result in Rider C collections or refunds related to losses. Both cost of losses and losses revenue vary with pool price, and the impact of lower or higher pool prices tends to affect both cost of losses and losses revenue to a similar extent.

The main cause of the net (\$7.7) million Rider C refund for 2004 noted in Table 4-4 was the recording in late 2004 of (\$5.2) million of prior period losses adjustments. These adjustments related to 2003 production periods, and are discussed in section 5.2.2 of the Application (page 56, lines 25-30). However, the adjustments result in a reduction to the losses deferral account balance, and they were therefore incorporated into the calculation of Rider C amounts which are determined to restore the deferral account balance to zero over the following quarter.

When cost and revenue amounts were assigned to their associated production periods in the deferral account reconciliation application, the result indicates an apparent significant overcollection through Rider C. However, Rider C for 2004 was reasonably

accurate in addressing deferral account balances for the year, and if the prior period adjustments discussed above are included, the 2004 net overcollection variance would have been (\$6.3) million, or 4.4% of costs. The AESO considers the magnitude of the variance to be reasonable considered the multiple factors that contribution to the losses deferral account.

**Preamble:** The AESO states:

The losses adjustment is a reduction to costs for a one-time adjustment related to a meter reading issue that ultimately resulted in a restatement of proprietary meter data of a specific customer over the years 2001, 2002, 2003. This one time adjustment impacted the value of system losses in all three years.

**Reference:** Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 56, Lines 9 – 12.

**Request:**

- (a) Please explain in detail the cause of this meter reading issue.
- (b) At what date(s) was the financial obligation(s) requiring adjustment to the deferral accounts created, and at what date(s) was it identified? When was it recorded in the AESO's accounts? When did the funds associated with this metering issue transfer between entities?
- (c) Where have amounts relating to the losses adjustment been recorded since the financial obligation was created?
- (d) Is the cause of the incorrect meter reading expected to be a recurring event in the future leading to further adjustments to losses? If so, has the AESO communicated with the AUC and stakeholders on the significance of such a potential event? Please provide any communications with the AUC or stakeholders in respect of any incorrect meter reading expected to reoccur and lead to further adjustments to losses.
- (e) Would any or all of the AESO customers have benefited through reduced costs (such as lower finance or credit charges) or increased revenue (such as investment or interest income) as a result of the financial obligation(s) being created? If so, which customer group (STS or DTS) would have benefited most? What would the amount of the benefit to each of STS and DTS be?

**Response:**

- (a) The adjustment of \$24.2 million relates to the restatement of energy market participant meter volumes for the period from 2001 to 2003. An overstatement of net supply volumes resulted in an overstatement of line losses during this period. The settlement adjustment amounts were derived by applying the hourly pool price to the restated hourly metered volumes.

When the issue was identified in 2004, the AESO began a review to identify the cause of the restatement and to determine if any corrective action needed to be taken to prevent

a reoccurrence. This review encompassed both the AESO's internal processes and those of the Wire Owner.

The AESO's findings from the review and input from Wire Owners confirmed that enhanced audit processes are required for revenue class meters. As part of the continuous review and improvement process related to meter data recording, collection, and reporting, the AESO continues to work with industry stakeholders that have legislated metering responsibilities to implement process enhancements.

Since 2001 when this meter issue began, the audit and process enhancements that have occurred have reduced the likelihood of a reoccurrence and increased the probability of earlier detection. These improvements have been made through joint initiatives with industry stakeholders.

To maintain the confidentiality of customer information, the AESO does not propose to provide specific details regarding the adjustments made in this case.

- (b-c) Please refer to attached Schedule TCE.AESO-002 (b-c).
- (d) As stated in part (a) above, the AESO and industry have taken measures to reduce the likelihood of an occurrence of a metering adjustment of this nature in the future.

In Information Response Comm.AESO-001 (b), the AESO identifies a further \$8 million in adjustments originating in metered volume restatements that will reduce the cost of losses in the years 2001 to 2005. The adjustments differ from the meter reading issue discussed in part (a) above as they relate to multiple settlement points rather than a single customer. The AESO believes the audit and process enhancements discussed in part (a) will also reduce the likelihood of further adjustments similar to these.

- (e) The refund to the AESO arising from the losses adjustment was used to generate about \$0.2 million of interest revenue from when the funds were received in July 2005 to September 2005. The refund was then used to reduce debt balances that would otherwise have been required, and therefore avoided interest expense. The AESO estimates its interest expense was reduced by about \$2.9 million from October 2005 to December 2007.

Interest revenue is a component of Other Revenue and is allocated in the same manner as Interconnection Charges in the AESO's deferral accounts. Interest expense is included in General and Administrative Costs and is also allocated in the same manner as Interconnections Charges in the AESO's deferral accounts. Interconnection Charges were allocated 58% to DTS customers and 42% to STS customers in 2005 and 100% to DTS customers in 2006 and 2007. Based on the interest revenue, the estimated interest expense reduction, and the allocation to DTS and STS customers in each year, approximately \$3.0 million would have accrued to DTS customers and \$0.1 million would have accrued to STS customers from June 2005 through December 2007.

**Preamble:** The AESO states:

A \$3.8 million adjustment in September 2004 and \$1.4 million adjustment in October 2004 both related to 2003. These amounts, together with several miscellaneous smaller adjustments comprise the \$16.6 million variance for 2003 losses since the first 2003 deferral account reconciliation.

**Reference:** Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 56, Lines 27 – 30.

**Request:**

- (a) Please provide explanations for the \$3.8 million over-collection adjustment in September 2004 and \$1.4 million over-collection adjustment in October 2004 relating to 2003.
- (b) At what dates were the financial obligations created requiring adjustment to the deferral accounts? When were they recorded in the AESO's accounts? When did the funds associated with these adjustments transfer between entities?
- (c) Where have the funds relating to these adjustments been recorded since the financial obligations were created?
- (d) Would any or all of the AESO customers have benefited through reduced costs (such as lower finance or credit charges) or increased revenue (such as investment or interest income) as a result of the financial obligations being created? If so, which customer group (STS or DTS) would have benefited most? What would the amount of the benefit to each of STS and DTS be?

**Response:**

- (a) These adjustments relate to the receipt of updated settlement information from Load Settlement Agents for energy market participant hourly load data. Energy market participant load data had been previously understated resulting in an overstatement of line losses in 2003. The settlement adjustment amount was derived by applying the hourly pool price to the restated hourly metered volumes.
- (b-c) Please refer to Schedule TCE.AESO-002 (b-c) provided as an attachment to Information Response TCE.AESO-002.
- (d) The refund to the AESO arising from the adjustment was used to reduce debt balances that would otherwise have been required, and therefore avoided interest expense. The AESO estimates its interest expense was reduced by about \$0.6 million from when the funds were received in the last quarter of 2004 to December 2007.

Interest expense is included in General and Administrative Costs and is accordingly allocated in the same manner as Interconnections Charges in the AESO's deferral accounts. Interconnection Charges were allocated 58% to DTS customers and 42% to STS customers in 2004 and 2005 and 100% to DTS customers in 2006 and 2007. Based on the estimated interest expense reduction and the allocation to DTS and STS customers in each year, approximately \$0.5 million of the estimated reduction would have accrued to DTS customers and \$0.1 million would have accrued to STS customers from the last quarter of 2004 through December 2007.

**Preamble:** The AESO indicates at page 48, Table 5-1, line 5 of the Application a post deferral account reconciliation adjustment of Enmax Power Corporation owing \$1.3 million.

The AESO also states at page 55, Lines 1 – 3, 10 – 13, 21 – 23:

**Line 1 AltaLink**

The second reconciliation recorded cost for AltaLink wires was \$150.8 million, which is \$14.7 million (or 11%) more than the first reconciliation recorded cost of \$136.1 million.

**Line 2 ATCO Electric**

The second reconciliation recorded cost for ATCO Electric transmission wires was \$144.3 million, which is \$11.8 million (or 9%) more than the first reconciliation recorded cost of \$132.5 million.

**Line 7 EPCOR Transmission Inc.**

The second reconciliation recorded cost for EPCOR Transmission wires was \$29.3 million, which is \$1.9 million (or 6%) less than the first reconciliation recorded cost of \$31.2 million.

**Reference:** Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 55, Lines 1 - 3, 10 - 13, 21 – 23.

Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 48, Table 5-1.

**Request:**

- (a) At what dates were the financial obligations requiring adjustment to the deferral accounts created?
- (b) Where have the funds relating to these adjustments been recorded since the financial obligations were created?
- (c) When did the funds associated with these adjustments transfer between the AESO and each of AltaLink, ATCO Electric, and EPCOR Transmission Inc.
- (d) At what date was the \$1.3 million dollar financial obligation for Enmax Power Corporation created? When was this recorded in the AESO's accounts? When did the funds associated with this adjustment transfer from Enmax Power Corporation into the AESO's account?
- (e) Please segregate the four adjustments regarding AltaLink's refund of \$14.7 million, ATCO Electric's refund of \$11.8 million, EPCOR's \$1.9 million under-collection, and

Enmax Power Corporation's refund of \$1.3 million into affected calendar years and by STS and DTS amounts.

**Response:**

- (a-e) Please refer to Schedule TCE.AESO-002 (b-c) provided as an attachment to Information Response TCE.AESO-002.

**Preamble:** The AESO states:

The largest of the 1999-2001 cost adjustments affect the interconnection charges deferral account balance, which has increased to an overcollection of \$7.7 million primarily due to adjustments resulting from EUB decisions affecting TFO revenue requirements as follows:

- a refund of \$7.0 million from TransAlta to reflect a reduction in federal income tax rates for 2001 and to reflect Rainbow Pipeline tax case results for 2001, ordered in Decision 2004-028 dated March 23, 2004, regarding TransAlta's Final Transmission Tariff for January 1 to April 30, 2002;
- a refund of \$0.6 million relating to an overpayment of a depreciation adjustment resulting from ATCO Electric's 2001-2002 Isolated Generation Application; and
- a refund of \$0.3 million from ATCO Electric to reflect tax savings from capital repair costs for 2001 ordered in Decision 2004-104 dated December 7, 2004, regarding ATCO Electric's Disposal of 2003 Transmission and Distribution Deferral Account Balances.

**Reference:** Application - Section 6 - Pre-2003 Deferral Account Adjustments, page 61, Line 9 – 20

**Request:**

- (a) At what dates were these financial obligations requiring adjustment to the deferral accounts created? When were they recorded in the AESO's accounts? When did the funds associated with these adjustments transfer between entities?
- (b) Where have the funds relating to these adjustments been recorded since the financial obligations were created?
- (c) Please segregate each of the three adjustments into affected calendar years and by STS and DTS amounts.

**Response:**

- (a-c) Please refer to Schedule TCE.AESO-002 (b-c) provided as an attachment to Information Response TCE.AESO-002.

**Preamble:** The AESO states:

The interconnection charges deferral account balance has also increased to an overcollection of \$15.3 million primarily due to adjustments resulting from the following EUB decisions regarding TFO tariffs:

- a refund of \$13.8 million from AltaLink due to the difference between interim and final TFO tariffs for 2002, ordered in Decision 2004-028 dated March 23, 2004, regarding AltaLink's Final Transmission Tariff for May 1 to April 30, 2004; and
- a refund of \$2.9 million from TransAlta to due to the difference between interim and final TFO tariffs for January to April 2002, ordered in Decision 2004-028 dated March 23, 2004, regarding TransAlta's Final Transmission Tariff for January 1 to April 30, 2002.

**Reference:** Application - Section 6 - 2002 Deferral Account Adjustments, page 63, Lines 4 - 12.

**Request:**

- (a) At what dates were these financial obligations requiring adjustment to the deferral accounts created? When were they recorded in the AESO's accounts? When did the funds associated with these adjustments transfer between entities?
- (b) Where have the funds relating to these adjustments been recorded since the financial obligations were created?
- (c) Please segregate both of the adjustments into affected calendar years and by STS and DTS amounts.

**Response:**

- (a-c) Please refer to Schedule TCE.AESO-002 (b-c) provided as an attachment to Information Response TCE.AESO-002.

**Preamble:** The AESO states:

The AESO anticipates that the automated deferral account reconciliation system developed for this application will allow future deferral account reconciliation applications to be filed about three months after the data cut-off date, resulting in filing in late November or early December following a data cut-off date of August 31.

**Reference:** Application - Appendix A - Conclusions of 2004-2005 Stakeholder Consultations, page 73.

**Request:**

Would the AESO be willing to commit to an annual fixed filing date of December 1 for the deferral account of the previous year? If not, why not?

**Response:**

As discussed in the cover letter to these information responses, the AESO proposes the current application be suspended and replaced by an extended application to be filed in May 2008 which would include a first reconciliation for deferral account years from 2004 to 2007. Unless filing the 2004-2007 application in May raises unanticipated issues, the AESO intends to file future deferral account application on an annual basis in the second quarter following the year to which the deferral account relates. Of course, consideration must be given to unusual circumstances that may delay a filing.

As well, if funds related to a large prior-period adjustment are expected to be received or disbursed by the AESO shortly after the data cut-off date that would enable a second quarter filing, the filing may be delayed so that the adjustment could be incorporated into the application.

As explained in the February 21 response to Technical Meeting Question 5, the AESO considers preparing a deferral account reconciliation application based on initial settlement data would have minimal impact on the accuracy of deferral account allocations to customers compared to waiting until after final settlement data is available. The discussion during the 2004-2005 stakeholder consultations about a late November or early December filing date was based on waiting for final settlement data which is not available until the end of August each year.

**Preamble:** The AESO states:

The AESO and stakeholders support the principle that the treatment of a material deferral account adjustment should not depend on when that adjustment happens. This principle leads to the conclusion that material adjustments must always be subject to full reconciliation. The AESO therefore proposes that full annual reconciliations be filed at least twice — the first reconciliation in the year following the deferral account, and the second reconciliation in the next year following.

**Reference:** Application - Appendix A - Conclusions of 2004-2005 Stakeholder Consultations, page 76.

**Request:**

How does the AESO propose to handle these large one-time, post period, adjustments in the future to insure that the appropriate customers receive their refunds in a timely manner and other customers are not unduly benefiting from direct or indirect surpluses in the AESO's deferral accounts?

**Response:**

The AESO recognizes the need to develop an approach that more effectively handles large deferral account transactions on an on-going basis. The AESO proposes to include such considerations in its 2008 deferral account application to be filed in 2009. If the approach includes revisions to Rider B or C, such revisions would be proposed as part of the AESO's next General Tariff Application or in a separate rider amendment application if appropriate.

**Preamble:** The AESO currently holds a \$19.2 million refund due to a one-time adjustment to income taxes affecting cost(s) for multiple years and ATCO deferral accounts decisions for 2005 and 2006.

**Reference:** AESO Responses to Technical Meeting Questions, Technical Meeting Question 6.

**Request:**

- (a) At what date(s) was the financial obligation created and what date(s) was it identified? When was it recorded in the AESO's accounts? When did the funds associated with this adjustment transfer between entities?
- (b) Where has the \$19.2 million refund been recorded since the financial obligation was created?
- (c) Would any or all of the AESO customers have benefited through reduced costs (such as lower finance or credit charges) or increased revenue (such as investment or interest income), as a result of the financial obligation being created? If so, which customer group (STS or DTS) would have benefited most? What would the amount of the benefit to each of STS and DTS be?

**Response:**

- (a-b) Please refer to Schedule TCE.AESO-002 (b-c) provided as an attachment to Information Response TCE.AESO-002.
- (c) The refund to the AESO arising from the adjustment will reduce debt balances that would otherwise have been required, and therefore will avoid interest expense. The AESO estimates its interest expense will be reduced by about \$0.4 million from January 2008 until settlement occurs as part of the deferral account process in or around June 2008.

Interest expense is included in General and Administrative Costs and is accordingly allocated in the same manner as Interconnections Charges in the AESO's deferral accounts. Interconnection Charges were allocated 100% to DTS customers in 2008, and the estimated reduction would accrue to DTS customers.

**Preamble:** In the above Application tables the lines for “Interest” are referenced.

**Reference:** Application - Section 4 - 2004 Financial Results and Deferral Account Balance, page 35, Table 4-1, Line 61.  
Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 50, Table 5-1, Line 57.  
Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 54, Table 5-2, Line 61.

**Request:**

- (a) Please provide a detailed explanation of what activities would create entries on these lines?
- (b) Are the amounts on these lines the net of interest paid and interest received?
- (c) Do these amounts include interest charged to customers or interest received on deposits or savings vehicles or both?
- (d) Do these amounts include interest paid for credit facilities to cover the AESO's costs in times of cash shortfall?
- (e) Does a zero entry on these lines mean that there was no activity in that year? Could it also mean there were significant amounts that offset to zero?

**Response:**

- (a) Interest expense is incurred by the AESO as a result of the following activities:
  - bank debt held throughout the year to provide working capital due to the timing difference in the collection of revenue and the payment of expenses, and to fund capital purchases;
  - credit facility standby fees, which are monthly charges on the undrawn portion of the bank's committed credit facility; and
  - fees charged related to the letter of credit issued as security for operating reserve procurement.
- (b) In 2003, interest revenue of \$0.4 million was netted against interest expense of \$0.4 million and shown in line 61 of Table 5-2 of the application as a balance of \$0.0 million (exact amount of \$2,360).

For 2004 and 2005, only interest expense (not net of interest revenue) is shown as “Interest” in line 61 of Table 4-1 for 2004, and in line 57 of Table 3-1 for 2005.

- (c) Interest expense is received by the AESO as a result of the following activities:
- interest earned on transmission customer security deposits;
  - charges to transmission customers for late settlement payments;
  - interest earned on invested funds which in certain circumstances were offset by payments to transmission customers for interest revenue earned while the AESO held security deposits and for a delay in cash settlement with a customer in bankruptcy proceedings in 2004.

Interest revenue is a line item grouped into Other Revenue and allocated in the same manner as Interconnections Charges in deferral account reconciliations. Interest expense is included in General and Administrative Costs and is accordingly allocated in the same manner as Interconnections Charges as well.

- (d) Yes. Please refer to part (a) above.
- (e) Please refer to part (b) above.

**Preamble:** At page 57, Table 5-3, line 9 of the Application, the AESO indicates revenues in the second reconciliation of 2003 are 3.8 million less than the first reconciliation of 2003.

At page 56, lines 45-47 of the Application, the AESO states:

On an annual basis, transmission revenue depends on approved transmission tariff rates (including both base rates and Rider C), pool price, and billed volumes of demand and energy. Variances arise due to unanticipated changes to billing volumes and pool price.

**Reference:** Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 56, Lines 45 – 47.

Application - Section 5 - 2003 Financial Results and Deferral Account Balance, page 57, Table 5-3.

**Request:**

Please specify the causes of the \$3.8 million revenue adjustment.

**Response:**

As a result of individual customer billing adjustments, revenues in 2003 were \$3.8 million lower in the second reconciliation compared to the first reconciliation which included revenues as of January 31, 2004. The adjustments resulted from:

- changes to contract terms which retroactively adjusted Customer-Owned Substation Credits and Regulated Generator Unit Connection Costs; and
- revenue adjustments resulting from new meter data.