AESO 2010 Tariff Stakeholder Consultation

John Martin, David Michaud, and Raj Sharma
AESO Regulatory
April 15, 2009 — Calgary

Reliable Power
Reliable Markets
Reliable People

Agenda

• Introduction (slides 1-6)
• Studies
  – POD cost function update (slides 7-17)
  – Maximum investment level update (slides 18-20)
  – TFO O&M cost causation study scope (slides 21-23)
• Rates
  – Restructuring of DTS operating reserve charge (slides 24-48)
  – Changes to DTS power factor deficiency charge (slides 49-52)
  – Changes to Fort Nelson Rate FTS (slides 53-54)
  – Possible higher priority (“firm”) export Rate XTS (slide 55)
  – Possible higher priority (“firm”) import Rate ITS (slides 56-57)
  – Changes to deferral account Riders B and C (slides 58-59)
Agenda (cont’d)

• Break
• Terms and conditions
  – Tariff changes in conjunction with TOAD project (slides 60-63)
  – Changes to interconnection process articles (slide 64)
  – Changes to AESO standard facilities definition (slides 65-67)
  – Amortized payment option for contributions (slides 68-69)
  – Further discussion on staged contributions (slide 70)
• Formation of working groups (slides 71-73)
• Next steps (slides 74-76)

Recent Applications

• AESO 2009 Rates Update
  – Filed March 12, 2009
  – 19% increase to DTS rate to reduce reliance on deferral account Rider C
  – Requested approval to be effective July 1, 2009
• AESO 2008 Deferral Account Reconciliation
  – Filed April 9, 2009
  – Reconciliation of $6.4 million net shortfall in deferral accounts
  – Requested interim approval to settle with customers in June 2009
AESO 2010 Tariff Application

- Plan to file in third quarter of 2009
- Stakeholder consultation February-June 2009
  - Individual stakeholder meetings held in February-March 2009
- Evolution of existing tariff
  - No major content changes (although potential movement between tariff and other authoritative documents)
  - Many minor changes
- Discussion papers and comment processes to review proposals
- Small working groups to develop specific issues

Meeting Objectives

- Understanding of preliminary results of studies being prepared for tariff application
- Discussion and development of scope and possible approaches for tariff proposals
- Set up working groups to address specific issues
- Establish expectations for remainder of consultation process and for filing of application
- Proposals are discussed “without prejudice” and may not be included or may be different in tariff application when filed
- Please ask questions during presentations
POD Cost Function and Investment Level Update

Raj Sharma
Senior Tariff Analyst, AESO Regulatory

Agenda

- Purpose
- Scope
- Method
- Inflation
- Raw cost function
- Upgrades
- Multiplier
- Proposed cost function
- Investment level implications
Purpose

- Update POD data set to include recent projects
  - 17 new projects since the last study
  - One project from last data set cancelled
  - Cost estimates may have changed or final costs may be available
- Examine which project cost inflator is appropriate
  - Alberta Consumer Price Index (CPI)
  - Composite index as proposed by Stakeholder Working Group
  - Composite index constructed by the AESO
- Compare the cost of upgrade projects to cost function
- Propose a new DTS POD cost function

Scope

- Update project information
- Include new projects
- Derive a project cost inflator index
- Determine raw greenfield interconnection project cost function
- Calculate cost per increased capacity for upgrade projects
- Calculate cost per capacity for greenfield projects
- Choose a multiplier
No Changes to Method Used in 2007 Refiling

- Included DTS-only projects that have no customer ownership
- Used latest project cost information (excluding 12% O&M)
  - Cost estimates ±20% or better or final costs
  - Based on cost of AESO Standard Facilities for project
- Project cost inflated to 2010 using Alberta CPI
- Determined relation between project cost and capacity
- Linearized the relation
- Divided the cost using Substation Fraction (SF)
- Used the existing multiplier of 1.15

Alberta CPI Is Close to Composite Price Index Over 1987-2007
Power Function Provides Highest Correlation for Raw Greenfield Cost

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function ($M)</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current (Power)</td>
<td>$y = 2.2131 + 2^{0.371/2}$</td>
<td>0.4041</td>
</tr>
</tbody>
</table>

Based on 48 projects from 1987-2007

<table>
<thead>
<tr>
<th>Analysis</th>
<th>Cost Function ($M)</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed (Power)</td>
<td>$y = 2.4423 + 2^{0.407/2}$</td>
<td>0.4331</td>
</tr>
<tr>
<td>Logarithmic</td>
<td>$y = 2.5994 \times \ln(x) + 1.7267$</td>
<td>0.3795</td>
</tr>
<tr>
<td>Linear</td>
<td>$y = 0.0972 \times x + 8.3146$</td>
<td>0.1834</td>
</tr>
<tr>
<td>Exponential</td>
<td>$y = 5.5314 \times e^{0.0131 \times x}$</td>
<td>0.2012</td>
</tr>
<tr>
<td>Cubic</td>
<td>$y = 6E-05 \times x^3 + 0.011 \times x^2 + 0.0125 \times x + 1.8761$</td>
<td>0.3432</td>
</tr>
<tr>
<td>Quadratic</td>
<td>$y = -0.0016 \times x^2 + 0.2633 \times x + 4.435$</td>
<td>0.3528</td>
</tr>
</tbody>
</table>

Based on 64 projects from 1987-2009

Update Cost Function Similar to Current Cost Function
Linear Cost Function With Same Breakpoints (7.5, 17 and 40 MW)

Upgrade Projects Adequately Covered by Cost Function
Preliminary DTS POD Cost Function

- DTS POD Cost
  \[ = \$0.959 \text{ million} + \$0.768 \frac{\text{million}}{\text{MW}} \times \text{first (7.5 \times SF) MW} + \$0.301 \frac{\text{million}}{\text{MW}} \times \text{next (9.5 \times SF) MW} + \$0.187 \frac{\text{million}}{\text{MW}} \times \text{next (23 \times SF) MW} + \$0.105 \frac{\text{million}}{\text{MW}} \times \text{remaining MW} \]

Linear Cost Function With Multiplier of 1.15

- Linearized Cost Function with Multiplier of 1.15
  \[ 100\%: 0, 50\%: 1/2, 0-50\%: 0, -50\%: 1/3 \]

- Graph showing linear cost function with and without multiplier.
### Multiplier of 1.15 Gives Results Similar to AUC 2007 Results

<table>
<thead>
<tr>
<th>Project Costs Covered by Investment</th>
<th>AUC 2007 Study with a multiplier of 1.15</th>
<th>AESO 2009 Study with a multiplier of 1.00</th>
<th>AESO 2009 Study with a multiplier of 1.15</th>
</tr>
</thead>
<tbody>
<tr>
<td>% receiving 100% investment</td>
<td>56%</td>
<td>48%</td>
<td>62%</td>
</tr>
<tr>
<td>% receiving 90-100% investment</td>
<td>12%</td>
<td>11%</td>
<td>11%</td>
</tr>
<tr>
<td>% receiving 80-90% investment</td>
<td>10%</td>
<td>12%</td>
<td>6%</td>
</tr>
<tr>
<td>% receiving 80-100% investment</td>
<td>79%</td>
<td>72%</td>
<td>80%</td>
</tr>
</tbody>
</table>

### Next Steps

- Discussion paper and stakeholder comments
- Refinements to study
- Finalization of study
- Apply for new cost function as part of 2010 tariff application
- Continue to collect data and analyze for future tariff applications
- Revisit the issue in next GTA
TFO O&M Cost Causation Study

Purpose

• Respond to AUC directions in decisions on AESO tariff applications
  – Determine percentage of TFO costs related to O&M that are energy related
  – Conduct further analysis of incremental TFO O&M costs
• Determine if a material percentage of TFO O&M costs are energy related
• Determine if transmission functionalization is the same for both capital and O&M costs
**TFO O&M Cost Causation Study Scope**

- Summarize TFO revenue requirement separating capital and O&M costs
  - Using most recent three years of TFO tariff filings
- Study O&M costs over facility life
- Determine relationship of O&M costs to:
  - Capital costs
  - Bulk system, local system, and POD transmission functions
  - Demand related, energy related, and fixed components

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**Operating Reserve Charge Investigation**

Raj Sharma  
Senior Tariff Analyst, AESO Regulatory
Agenda

- Purpose
- Observation
- Possible rates
- Criteria
- Method
- Results
- Sensitivity and further analysis
- Further Results
- Selection
- Performance

Current Charge Results in Large Deferral Account Balances
Changes in Operating Reserve Costs Are Related to Pool Price

Possible Rates That Are a Stronger Function of Pool Price

- Hourly On/Off-Peak: x1 for 7am-11pm and x2 for 11pm-7am
- Block: x1 when PP is <=P1 and x2 when PP is > P1
- Exponential: x1 \cdot \exp(PP \cdot x2)
- Linear: x1 \cdot PP + x2
- Quadratic: x1 \cdot PP^2 + x2 \cdot PP + x3
- Power: x1 \cdot PP^{x2}
- Block Continuous: x1 \cdot PP when PP <=P1 plus an additional x2 \cdot (PP-P1) when PP > P1
- Block Continuous with a Floor: F + x1 \cdot PP when PP <=P1 plus an additional x2 \cdot (PP-P1) when PP > P1
Criteria

- Recover forecasted annual OR cost
- Minimize monthly variance between cost and revenue
- Sensitivity to Pool Price
- Sensitivity to DTS MWh volume
- Simplicity
- Clarity
- Easy to administer

Method

- For each year, forecast a rate that recovers forecasted annual cost using forecasted hourly PP and forecasted hourly DTS MWh
- Calculate actual revenues using this forecasted rate, actual hourly PP, and actual hourly DTS MWh
- Compare performance of this rate to other rates
- Compare sensitivity of this rate to other rates
- Further analyze rate that performs best
**Monthly RMS Variance**

<table>
<thead>
<tr>
<th>Rate</th>
<th>Monthly RMS ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2006</td>
</tr>
<tr>
<td>Hourly On/Off-Peak</td>
<td>6.37</td>
</tr>
<tr>
<td>Block</td>
<td>5.35</td>
</tr>
<tr>
<td>Exponential</td>
<td>14.69</td>
</tr>
<tr>
<td>Linear</td>
<td>6.29</td>
</tr>
<tr>
<td>Quadratic</td>
<td>64.71</td>
</tr>
<tr>
<td>Power</td>
<td>14.72</td>
</tr>
<tr>
<td>Block Continuous</td>
<td>4.64</td>
</tr>
<tr>
<td>Block Continuous With Floor</td>
<td>25.05</td>
</tr>
<tr>
<td>Actual</td>
<td>5.83</td>
</tr>
</tbody>
</table>

*P1 was rounded average of forecasted hourly PP*
Sensitivity — 2007

Sensitivity — 2008
**Best Rate**

- Block Continuous rate appears to perform best
- In order to make the rate more deterministic, block size (i.e. P1) and ratio of the rates in two blocks (i.e. x1 and x2) can be fixed
- Varied P1 from $120-$180/MWh and ratio of the rates from 2-4 (i.e. x2 is 2-4 times x1)

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**Best Block Continuous Rate for Each Year**

- **2006**
  - Performs best when x2 is 2 times x1
  - Monthly RMS error is $3.2 million; annual error is $20 million
  - For P1=$150/MWh, x1=3.62% and x2=7.25%
- **2007**
  - Performs best when x2 is 3 times x1
  - Monthly RMS error is $2 million; annual error less than $2 million
  - For P1=$150/MWh, x1=3.44% and x2=10.32%
- **2008**
  - Performs best when x2 is 4 times x1
  - Monthly RMS error is $5 million; annual error less than $1.5 million
  - For P1=$150/MWh, x1=2.89% and x2=11.57%
Best Block Continuous Rate

• Three block rate reduced monthly RMS variance range by about $1-2 million
  – AESO proposes to make gradual changes to the OR rate and believes that additional complexity is not warranted at this time
• P1 can vary between $120-$180/MWh without degrading the results too much
• Ratio of the rates has significant effect on resulting variance

Best Block Continuous Rate (cont’d)

• Years that are expected to be similar to the immediate future should be given more consideration
  – 2008 had higher number of power plant outages and large variation in natural gas price
  – Because of economic downturn, Pool Price and thus Operating Reserve cost in 2009 is expected to be lower than in 2008
  – Approval of WECC BAL-002 standard will reduce Operating Reserve requirement thus possibly reducing OR cost
  – 2006 forecast was very different from the actual. Forecasting has improved since then and the difference has been quite small in 2007 and 2008
Rate Selection — Ratio of 3

Best Rate — Ratio of 2.5 Best Overall

<table>
<thead>
<tr>
<th>Ratio</th>
<th>Variance</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>Average Variance 2006-08</th>
<th>Absolute Average Variance 2006-08</th>
<th>Range 2006-08</th>
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<tbody>
<tr>
<td>2</td>
<td>Maximum</td>
<td>7.68</td>
<td>2.25</td>
<td>6.32</td>
<td>5.42</td>
<td>5.42</td>
<td>10.71</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>-3.81</td>
<td>-10.88</td>
<td>-12.39</td>
<td>-9.03</td>
<td>9.03</td>
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<tr>
<td></td>
<td>Average</td>
<td>1.74</td>
<td>-1.01</td>
<td>-1.73</td>
<td>-0.33</td>
<td>1.49</td>
<td></td>
</tr>
<tr>
<td>2.5</td>
<td>Maximum</td>
<td>8.32</td>
<td>2.10</td>
<td>6.64</td>
<td>5.71</td>
<td>5.71</td>
<td>17.53</td>
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<tr>
<td></td>
<td>Minimum</td>
<td>-0.36</td>
<td>-5.53</td>
<td>-10.89</td>
<td>-5.59</td>
<td>5.59</td>
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<tr>
<td></td>
<td>Average</td>
<td>3.44</td>
<td>-0.45</td>
<td>-1.19</td>
<td>0.60</td>
<td>1.69</td>
<td></td>
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<tr>
<td>3</td>
<td>Maximum</td>
<td>13.29</td>
<td>3.06</td>
<td>6.91</td>
<td>7.75</td>
<td>7.75</td>
<td>16.54</td>
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<tr>
<td></td>
<td>Minimum</td>
<td>0.22</td>
<td>-4.19</td>
<td>-9.63</td>
<td>-4.53</td>
<td>4.68</td>
<td></td>
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<tr>
<td></td>
<td>Average</td>
<td>5.11</td>
<td>0.06</td>
<td>-0.73</td>
<td>1.48</td>
<td>1.97</td>
<td></td>
</tr>
</tbody>
</table>
2006-2008 Variance for a Ratio of 2.5

2009 Rate for Ratio of 2.5
Proposed Operating Reserve Charge

- The **Operating Reserve Charge** equals:
  
  (a) For each hour in which Pool Price is less than or equal to $150.00/MWh:
      - Metered Energy × 4.47% × Pool Price
  
  plus

  (b) For each hour in which Pool Price is greater than $150.00/MWh:
      - Metered Energy × ((11.18% × Pool Price) – $10.07/MWh)
Performance of the Proposed Rate

Next Steps

- Discussion paper and stakeholder comments
- Revise
- Finalize
- Apply for the new rate
- Monitor performance of the new rate
- Continue to examine if three block rate results in significant improvement
- Revisit the issue in next GTA
Potential Changes to DTS Power Factor Deficiency Charge

- Current DTS rate includes power factor deficiency charge of "$400.00/MVA of Apparent Power Difference when Power Factor is less than 90% during the interval of highest Metered Demand in the Billing Period"
  - "Apparent Power Difference" is calculated during the interval of highest Metered Demand in the Billing Period as the difference between the metered Apparent Power and 111% of the Metered Demand
  - Charges do not apply at dual-use sites where generator responds to System Controller directions
- Poor power factor is resulting in constraints in some areas and causing unnecessary system losses
- Poor power factor identified as factor in power outages
Power Factor Deficiency Charge Comparison

Power Factor Deficiency Charge Possible Considerations

- Power factor requirement: 90%? 95%?
- Measure at time of system peak, non-coincident customer peak, or continuously
- Discontinue waivers at sites with generation subject to system controller direction
- Penalty could increase as power factor worsens
- Power factor charge reflective of customer cost of correction or system cost of correction
Potential Changes to Fort Nelson Rate FTS

- AESO planned northwest transmission development to remove need for transmission must run ("TMR") service in Rainbow Lake area
- Potential load growth in Fort Nelson area in BC could require continued use of TMR
  - Load growth in Rainbow Lake area greater in BC than in Alberta
- Incremental post-northwest development costs could be prorated between BC and Alberta based on incremental post-northwest development load growth
  - BC would receive incremental cost signal to drive appropriate transmission development choices

Fort Nelson Rate FTS Considerations

- Using incremental cost and load post-northwest development would recognize history of transmission supply to Fort Nelson from Alberta
- Costs charged to BC Hydro at Fort Nelson could be greater of postage stamp DTS rate component or incremental cost component
  - Similar to basis for current rate
- Costs could be recovered as monthly tariff charge
  - Would require appropriate termination provisions
Possibilities for Higher Priority Export Rate XTS

- Rate XTS proposed by AESO in 2007 GTA but rejected by interveners and AUC
  - Limited available transfer capacity ("ATC") in some hours
  - Cost too high
- Have conditions changed materially since 2007?
  - ATC still limited
- Is a new export service needed before Edmonton-Calgary reinforcement is complete?

Possibilities for Higher Priority Import Rate ITS

- Higher priority import rates examined previously but were considered to be too similar to existing opportunity rate
  - Recent interest in an import rate with priority similar to STS
- What minimum and maximum terms should apply to a higher priority ("firm") import rate?
- Should it include "take or pay" provisions?
- Should it include provisions for direct charging for ancillary services if required to support the import?
- Should it require a refundable payment like the generator system contribution?
  - What minimum capacity factor or other criteria should apply?
Issues With Additional Export and Import Services

- How to address AUC concern with allocating deep system costs to exports and imports over merchant lines?
- Additional priority rates require OASIS or similar system
  - Higher priority export opportunity rate already approved in AESO tariff but will not be available until OASIS is implemented

Potential Changes to Deferral Account Rider C

- Rider C purpose is “to restore the deferral account balances to zero over the following calendar quarter”
  - Requires forecasting of the upcoming quarter
  - For example, must forecast Q1 variance to determine Q1 Rider C
- Alternatively, could use only actual variances
  - May decrease Rider C variability
  - May cause AESO to hold surpluses and finance shortfalls longer
- Alternatively, could address variances over remaining months in calendar year, as opposed to next quarter
  - Similar to Rider E approach
- Could vary approach by rate component
Potential Changes to Deferral Account Rider B

- Rider B purpose is to recover unexpected deficiencies or refund unexpected surpluses of working capital.
- Currently available only as a “percentage increase or decrease…applied to charges under the rate schedules…in the current Billing Period”
- Revise to allow for more specific implementation:
  - By rate component
  - By MWh (like Rider C)
- Potentially possible to modify Rider C to accommodate Rider B purpose.

Terms and Conditions Changes

John Martin
Director, Tariff Applications, AESO Regulatory
Tariff Changes in Conjunction With TOAD Project

- Transition of Authoritative Documents (“TOAD”) project will develop structure and framework for AESO authoritative documents
  - Three years to move documents to new framework
- AESO tariff is an authoritative document
- What tariff changes should be accommodated as part of TOAD project?
  - Tariff approval has longer timeline that other document approvals

Potential Changes in Conjunction With TOAD Project

- Move technical requirements currently in tariff to AESO technical standards
  - PSS and AVR requirements in Article 4
  - Metering requirements in Article 7
  - Metering equipment information in Appendix A
- Standardize and consolidate common requirements
  - Master set of definitions for all authoritative documents (Article 1)
  - Single dispute resolution process (Article 19)
  - Single set of confidentiality provisions (Article 20)
Potential Changes in Conjunction With TOAD Project (cont’d)

- Consolidate information that is currently dispersed
  - Interconnection process (Ts&Cs and business practices)
  - DOS requirements (rates, Ts&Cs, OPPs, business practices)
  - Where should such consolidated information reside?
- Must be able to articulate rationale for where information ultimately end up
- Should terms and conditions migrate to authoritative document format?

Potential Changes to Interconnection Process Articles

- Articles 4, 5, 6, and 13 deal with the process of providing system access service to a customer
- Business practice documents support this process
- Interconnection process continues to evolve at AESO
- How much detail is appropriate to tariff?
- What details can be left to business practice documents?
- How do we allow flexibility for future improvements to process?
Contribution Policy Changes

David Michaud
Manager, AESO Regulatory

Potential Changes to AESO Standard Facilities Definition

• Current definition:

  “AESO Standard Facilities” mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consists of a single radial transmission circuit and a single transformer to supply an individual Point of Connection
AltaLink Consultation Recommendations

- Guiding Principal 2.0, Recommendation 1:
  "AESO Standard Facilities" mean the most economical interconnection facilities which meet good utility practice including applicable reliability, protection, and operating criteria and standards
- Appendix A.1 – Standards of Service:
  Standards to serve as a guide for number of transformers (two transformers to supply a POD with peak loads above 15 MVA) and number of lines, with rural, urban, and industrial distinctions

Amortization Payment Options for Customer Contributions

- Management fee on customer contributions as part of the TFO revenue requirement
  - Proposed in ATCO Electric and AltaLink tariff applications
  - Could apply to all rate payers or just to customers paying contributions
- Optional rider added to AESO tariff (Amortized Customer Contribution Rider)
Issues With Amortization Payment Options

- Optional or mandatory?
- Conversion options?
  - One-time option
  - Available to new customers only or to all customers?
- Amortization term?
- Fairness to new and existing customers
- Available to DTS and STS customers?
  - Available for generator system contributions as well?
- Risk of default
- Rate based on TFO return on equity

Staged Contributions

- Contributions are currently paid before construction
- Could contributions be paid in installments with the final payment occurring prior to energization?
  - Aligned with costs incurred by TFO
- Potential issues:
  - Timing of payments
  - Risk of default
  - Fairness to new and existing customers
  - Who will administer?
  - Is rate of return applicable?
Next Steps

John Martin
Director, Tariff Applications, AESO Regulatory

Formation of Working Groups

• Possible working groups to explore:
  – Fort Nelson Transmission Service Rate FTS
  – export and import rates ETS and ITS
  – deferral account Riders B and C
  – tariff changes in conjunction with TOAD project
  – amortized payment option and other customer contribution matters

• Working groups would identify issues and explore alternatives

• Working groups would not be decision making body
  – Final decisions would be made by AESO
Formation of Working Groups (cont'd)

- Working group target size around 4-6 participants
- Working groups would meet every two weeks
- How to select working group participants?
- How to select working group topics and scope?

Next Steps

- AESO to prepare and distribute discussion material by end of April
  - Including forms for stakeholder comment
- Next large stakeholder meeting near end of May
Discussion and Questions

For More Information

• John Martin
  Director, Tariff Applications
  403-539-2465 or john.martin@aeso.ca

• David Michaud
  Manager, Regulatory Services
  403-539-2471 or david.michaud@aeso.ca

• Raj Sharma
  Senior Tariff Analyst
  403-539-2632 or raj.sharma@aeso.ca

• Consultation documents on AESO web site at www.aeso.ca
  Tariff ▶ Current Consultations ▶ 2010 Tariff