AESO 2014 ISO Tariff Application
General Technical Meeting

John Martin, Director, Tariff Applications
Raj Sharma, Senior Tariff Analyst
August 8, 2013 — Calgary, Alberta

Agenda

• Application and background
• Revenue requirement
• Consultation
• 2013 tariff update
• Transmission cost causation
• Rate design

Break

• Terms and conditions
• Responses to directions
• Appendices

Please ask questions during the presentation
Application and background

- AESO filed 2014 ISO Tariff Application and 2013 ISO Tariff Update on July 17, 2013
  - Error in 2014 rate calculations identified after filing
  - Affected components revised and refiled July 19, 2013

- 20 parties have registered in proceeding

- Two technical meetings are being held
  - General meeting on August 8, 2013
  - Cost causation study technical meeting on August 19 with London Economics (consultants who prepared the study)

- Commission will establish schedule for proceeding
  - AESO estimates oral hearing may be held in November 2013
  - AESO estimates decision may be issued in March 2014

Application and background (cont’d)

- AESO is not seeking approval of revenue requirement
  - Costs of transmission wires are approved by Commission through transmission facility owner tariff proceedings
  - Costs of ancillary services, losses, and administration are approved by AESO Board
    - Must be considered “prudent” unless an interested person satisfies the Commission otherwise

- Current ISO tariff became effective on July 1, 2011
  - Resulting from 2010 application and 2011 compliance filing

- Application includes 2013 tariff update in accordance with annual tariff update process contemplated in Decision 2010-606
  - Approval requested for October 1, 2013 effective date
Application and background (cont’d)

- Application primarily proposes 2014 tariff changes based on comprehensive review of rates and terms and conditions
  - Responds to directions in tariff decisions, including Decision 2012-362 on AESO 2012 Construction Contribution Policy Application
  - Reflects consideration of stakeholder input provided through consultation
  - Addresses other matters identified by the AESO
  - Approval requested for July 1, 2014 effective date

- Revised construction commitment agreement not finalized at time of filing and will be provided as soon as possible

Revenue requirement
($2 p 9)

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>2011 Approved</th>
<th>2013 Forecast</th>
<th>Increase (Decrease) Over 2011</th>
<th>2014 Projected</th>
<th>Increase (Decrease) Over 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$000,000</td>
<td>$000,000</td>
<td>%</td>
<td>$000,000</td>
<td>$000,000 %</td>
</tr>
<tr>
<td>Wires</td>
<td>786.2</td>
<td>1,114.3</td>
<td>328.1</td>
<td>1,398.8</td>
<td>284.5</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>96.0</td>
<td>259.2</td>
<td>163.2</td>
<td>244.6</td>
<td>(14.6)</td>
</tr>
<tr>
<td>Losses</td>
<td>121.0</td>
<td>136.9</td>
<td>15.9</td>
<td>123.7</td>
<td>(13.2)</td>
</tr>
<tr>
<td>Administration</td>
<td>83.0</td>
<td>103.2</td>
<td>20.2</td>
<td>106.6</td>
<td>3.4</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>1,086.2</td>
<td>1,613.6</td>
<td>527.4</td>
<td>1,873.7</td>
<td>260.1</td>
</tr>
</tbody>
</table>
2013 wires cost forecast
(§ 2.2 pp 12-15)

- Decision 2010-606 approved forecast of transmission facility owner tariff costs based on status of their tariff applications

<table>
<thead>
<tr>
<th>Status of Application</th>
<th>TFOs</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) Final approval for 2013 TFO tariff</td>
<td>Red Deer</td>
</tr>
<tr>
<td></td>
<td>FortisAlberta (farm transmission)</td>
</tr>
<tr>
<td>(b) Compliance filing after initial decision on 2013 TFO tariff</td>
<td>—</td>
</tr>
<tr>
<td>(c) 72% of 2013 applied-for increase over last approved TFO tariff</td>
<td>AltaLink</td>
</tr>
<tr>
<td></td>
<td>ATCO Electric</td>
</tr>
<tr>
<td></td>
<td>ENMAX</td>
</tr>
<tr>
<td></td>
<td>Lethbridge TFO</td>
</tr>
<tr>
<td>(d) Most recently approved TFO tariff</td>
<td>EPCOR (2012 final)</td>
</tr>
<tr>
<td></td>
<td>TransAlta (2012 interim)</td>
</tr>
</tbody>
</table>

2014 wires cost projection
(§ 2.2 pp 12-15)

- Wires cost forecast approach not used for 2014 as several transmission facility owners had not yet applied for 2014 tariffs
- AESO instead used projection of wires costs based on existing approved TFO revenue requirements plus revenue requirement expected from 2014 capital expenditures
  - Calculated in transmission rate impact projection workbook
- 2014 wires cost will be updated using the forecast approach in any tariff compliance filing required for the 2014 rates in the application
Other 2013 and 2014 costs
(§ 2.3-2.5 pp 15-17)

- 2013 costs for ancillary services, losses, and administration are as approved by AESO Board
- 2014 costs for ancillary services, losses, and administration are as included in transmission rate impact projection
  - 2014 ancillary services based on pool price forecast
  - 2014 losses based on pool price forecast
  - 2014 administration based on escalation of 2013 administration
    - Escalated by forecast increase in Alberta average weekly earnings

Consultation
(§ 3 pp 18-19)

- AESO conducted consultation for 2014 tariff application from November 2012 to June 2013
  - Small working group to review cost causation and related matters
  - Two general stakeholder meetings
  - More focused stakeholder meetings on specific topics
- Cost causation working group held eight consultation meetings
  - Reviewed drafts of transmission cost causation study prepared by London Economics
2013 tariff update
(§ 4 p 20)

• Rate changes
  – Updates to all rate levels
  – Rate XOM, Export Opportunity Merchant Service
  – Rate PSC, Primary Service Credit
  – Rate STS, Supply Transmission Service (RGUCC charge)
  – Rider J, Wind Forecasting Service Cost Recovery Rider

• 2013 maximum investment levels

Updates to rate levels
(§ 4.1 pp 20-21)

• 2012 tariff update not filed
  – Department of Energy requested prohibition on rate increases
  – Commission implemented through Bulletin 2012-03

• 2013 rates update uses rate calculations approved in Decision 2010-606 on AESO 2010 tariff application
  – 2013 revenue requirement forecast
  – 2013 billing determinants forecast

• Reduces amount of revenue shortfall that would be initially collected through Rider C, Deferral Account Adjustment Rider, and later re-allocated in deferral account reconciliation
Changes to Rate DTS levels
(§ 4.1 pp 20-21 and Appendix C)

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>2011 Charge</th>
<th>2013 Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bulk System Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Coincident metered demand</td>
<td>$3,313/MW</td>
<td>$5,033/MW</td>
</tr>
<tr>
<td>• Metered energy</td>
<td>$1.17/MWh</td>
<td>$1.68/MWh</td>
</tr>
<tr>
<td><strong>Local System Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Billing capacity</td>
<td>$972/MW</td>
<td>$1,243/MW</td>
</tr>
<tr>
<td>• Metered energy</td>
<td>$0.49/MWh</td>
<td>$0.70/MWh</td>
</tr>
<tr>
<td><strong>Point of Delivery Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Substation fraction (SF)</td>
<td>$8,544</td>
<td>$10,926</td>
</tr>
<tr>
<td>• First (7.5 × SF) MW of billing capacity</td>
<td>$5,788/MW</td>
<td>$7,401/MW</td>
</tr>
<tr>
<td>• Next (9.5 × SF) MW of billing capacity</td>
<td>$2,136/MW</td>
<td>$2,732/MW</td>
</tr>
<tr>
<td>• Next (23 × SF) MW of billing capacity</td>
<td>$1,294/MW</td>
<td>$1,655/MW</td>
</tr>
<tr>
<td>• All remaining MW of billing capacity</td>
<td>$709/MW</td>
<td>$907/MW</td>
</tr>
<tr>
<td><strong>Operating Reserve Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Hourly costs allocated on metered energy or</td>
<td>2.35%</td>
<td>5.16%</td>
</tr>
<tr>
<td><strong>Voltage Control Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Metered energy</td>
<td>$0.51/MWh</td>
<td>$0.03/MWh</td>
</tr>
<tr>
<td><strong>Other System Support Services Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Highest metered demand</td>
<td>$55/MW</td>
<td>$20/MW</td>
</tr>
</tbody>
</table>

Export Opportunity Merchant Service
(§ 4.1 pp 21-22)

• Cost of losses over Alberta-Montana intertie will be excluded from AESO revenue requirement in accordance with section 27 of Transmission Regulation

• Existing Rates XOS, Export Opportunity Service, includes both loss charges and losses calibration factor charges or credits
  – Even if loss factor was set to zero, calibration factor would be non-zero and would still apply

• AESO has proposed a modified export rate, Rate XOM, to remove losses-related components from Rate XOS
  – All other aspects of Rate XOM remain the same as Rate XOS

• AESO has requested expedited approval as Alberta-Montana intertie will enter commercial operation during 2013
### Primary Service Credit

($\S$ 4.1 p 22)

- AESO has calculated Primary Service Credit as percentage of updated Rate DTS point of delivery charge
- Same methodology as in current tariff

### Regulated Generating Unit Connection Cost Charge in Rate STS

($\S$ 4.1 pp 22-23)

- Regulated generating unit connection cost charge is based on cost of transmission facilities originally built to connect previously-regulated generating units
- Schedule of annual charges to 2020 filed in AESO’s 2007 tariff application proceeding
  - RGUCC charge decreases every year reflecting on-going amortization of connection costs over lives of previously-regulated generating units
- Charge applicable to 2013 is $192/MW
  - Current charge is $237/MW
Wind Forecasting Service Cost Recovery Rider (§ 4.1 pp 22-23)

- Rider J first implemented in 2011
- Updated to reflect variances from forecasts of cost and energy
- Charge applicable to 2014 is $0.16/MWh
  - Current charge is $0.15/MWh
  - Annual escalation of $0.01/MWh proposed to continue for 2014

2013 bill impact (§ 4.3 pp 24-25)

<table>
<thead>
<tr>
<th></th>
<th>2011 Recorded</th>
<th>2013 Forecast</th>
<th>Increase (Decrease)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue Requirement ($ 000 000)</td>
<td>$1,433.4</td>
<td>$1,613.6</td>
<td>$180.2</td>
</tr>
<tr>
<td>Rate DTS Energy (GWh)</td>
<td>55,196.0</td>
<td>59,604.0</td>
<td>4,408.0</td>
</tr>
<tr>
<td>Revenue Requirement per Unit ($/MWh)</td>
<td>$25.97</td>
<td>$27.07</td>
<td>$1.10</td>
</tr>
</tbody>
</table>
Updated Rate DTS levels will reduce Rider C charge (§ 4.3 pp 24-25)

- Updating 2013 rate levels will reduce amounts collected through Rider C
- Rider C level currently collecting $6.15/MWh
  - Primarily reflecting connection charge component
  - Will collect about $360 million through Rider C during 2013
  - Represents about 24% of Rate DTS revenue requirement
- Rider C amounts will be re-allocated in 2013 deferral account reconciliation
  - Expected to be filed in early 2014

2013 inflation index
(§ 4.4 pp 25-26)
2013 maximum investment levels
(§ 4.4 pp 25-26)

- Decision 2010-606 approved increases to maximum investment levels based on composite inflation factor
- Escalation factor from 2011 to 2013 was 1.039

<table>
<thead>
<tr>
<th>Investment Tier</th>
<th>2011 Level</th>
<th>2013 Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation fraction (SF)</td>
<td>$50 050/year</td>
<td>$52 000/year</td>
</tr>
<tr>
<td>First (7.5 × SF) MW of contract capacity</td>
<td>$34 000/MW/year</td>
<td>$35 350/MW/year</td>
</tr>
<tr>
<td>Next (9.5 × SF) MW of contract capacity</td>
<td>$12 550/MW/year</td>
<td>$13 050/MW/year</td>
</tr>
<tr>
<td>Next (23 × SF) MW of contract capacity</td>
<td>$7 600/MW/year</td>
<td>$7 900/MW/year</td>
</tr>
<tr>
<td>All remaining MW of contract capacity</td>
<td>$4 100/MW/year</td>
<td>$4 250/MW/year</td>
</tr>
</tbody>
</table>

2013 tariff update implementation
(§ 4.5 p 27)

- Update is simple and formulaic using methodology contemplated in Decision 2010-606
- AESO requested expedited approval through written process
- Requested effective date of October 1, 2013
Transmission cost causation
(§ 5 pp 28-29)

- Decision 2010-606 directed the AESO to file an updated transmission system cost causation study
- Six quotations received for study
- AESO contracted London Economics to complete study
- Transmission cost causation study will be examined in second technical meeting
  - Functionalization into bulk system, regional system, and point of delivery
  - Classification of bulk system and regional system costs
  - Both capital and operating and maintenance costs for transmission system
- Point of delivery cost function updated separately by AESO

Transmission cost causation study
(§ 5.2 pp 29-31)

- Same general approach as previous studies filed with 2006, 2007, and 2010 tariff application

```
<table>
<thead>
<tr>
<th>“Wires” Costs</th>
<th>Functionalization</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Facility</td>
<td>Bulk System</td>
<td>Demand</td>
</tr>
<tr>
<td>Owner Costs</td>
<td>Regional System</td>
<td>Energy</td>
</tr>
<tr>
<td></td>
<td>Point of Delivery</td>
<td></td>
</tr>
</tbody>
</table>
```
Transmission cost causation study (cont’d) (§ 5.2 pp 29-31)

- Transmission costs analyzed over 2014-2016 period
  - Expected term of the tariff being applied for
- Comments provided to the AESO on implementation of results of study into rate design

Transmission cost functionalization (§ 5.2 pp 29-31)

- Higher proportion of costs functionalized as bulk system and regional system
- Lower proportion of costs functionalized as point of delivery

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td>41.7%</td>
<td>55.2%</td>
<td>61.2%</td>
<td>62.0%</td>
</tr>
<tr>
<td>Regional System</td>
<td>17.4%</td>
<td>22.5%</td>
<td>20.1%</td>
<td>19.6%</td>
</tr>
<tr>
<td>Point of Delivery</td>
<td>40.9%</td>
<td>22.3%</td>
<td>18.7%</td>
<td>18.4%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Transmission cost classification  
(§ 5.2 pp 29-31)

- Higher proportion of bulk system costs classified as demand-related
- Higher proportion of regional system costs classified as demand-related

<table>
<thead>
<tr>
<th>Classification</th>
<th>2011</th>
<th>2014-2016</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bulk</td>
<td>Regional</td>
</tr>
<tr>
<td>Demand-Related</td>
<td>82.0%</td>
<td>82.0%</td>
</tr>
<tr>
<td>Energy-Related</td>
<td>18.0%</td>
<td>18.0%</td>
</tr>
</tbody>
</table>

Point of delivery cost function  
(§ 5.3 pp 31-32)

- Point of delivery costs classified based on “best fit” power curve of cost as function of capacity
- Power curve based on participant-related costs at load-only substations
- Approach was developed during 2007 tariff application proceeding
- Cost function updated as in 2012 Construction Contribution Policy Application
  - Updated connection project database
  - Revised inflation index
  - Incorporation of upgrade projects
Connection project database
(§ 5.3 pp 32-33)

- Used only projects at or past facilities application stage
  - Provides greater certainty of configuration and costs
- Used maximum contracted capacity for project
  - Reflects design capacity of substations when load is staged
- All connection project data updated to early 2012
  - Same data as used for 2012 Construction Contribution Policy Application
- Incorporated upgrade project data

<table>
<thead>
<tr>
<th></th>
<th>2010 Analysis</th>
<th>2014 Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Updated data period</td>
<td>1999-2009</td>
<td>1999-2013</td>
</tr>
<tr>
<td>Greenfield projects</td>
<td>64 greenfield projects (46 AESO-era and 18 pre-AESO)</td>
<td>87 greenfield projects (69 AESO-era and 18 pre-AESO)</td>
</tr>
<tr>
<td>Cost data source</td>
<td>final costs and PPS estimates</td>
<td>final costs and PPS estimates where facilities applications have been filed</td>
</tr>
<tr>
<td>Total greenfield project costs, uninflated</td>
<td>$467.7 million</td>
<td>$870.2 million</td>
</tr>
<tr>
<td>Total greenfield project costs, inflated</td>
<td>$553.5 million</td>
<td>$1,127.7 million</td>
</tr>
<tr>
<td>Upgrade projects</td>
<td>not included</td>
<td>128 upgrade projects</td>
</tr>
<tr>
<td>Total upgrade project costs, uninflated</td>
<td>-</td>
<td>$343.5 million</td>
</tr>
<tr>
<td>Total upgrade project costs, inflated</td>
<td>-</td>
<td>$414.7 million</td>
</tr>
</tbody>
</table>
Inflation index
(§ 5.3 pp 34-35)

- Escalated project costs starting from year before project’s in-service date
  - Recognizes that material and construction costs are typically incurred 6 to 18 months prior to in-service date

- Inflation index comparable to that approved by Commission in Decision 2012-237 with respect to rate regulation initiative for distribution system owners in Alberta
  - For equipment, 35% of Alberta Consumer Price Index (CPI) from Statistics Canada
  - For labour, 65% of Alberta Average Weekly Earnings (AWE) index from Statistics Canada

- Weighting based on results of the AESO’s analysis of transmission projects in Alberta

Inflation index (cont’d)
(§ 5.3 pp 34-35)

- Proposed two-component index is simpler than previous four-component index

- Two-component index is based on widely-used Statistics Canada indices that are unlikely to be discontinued
  - One component of four-component index has been discontinued

- Two-component index exhibits less volatility than four-component index

- Two-component index is slightly higher than four-component index
  - Averages 3.31% compared to 2.95% over 1997-2011
Cost function from greenfield projects
(§ 5.2 pp 36-41)

\[ y = 2.5338x^{0.5192} \]

\[ R^2 = 0.3747 \]

Note: Five data points lie outside the bounds of this chart. For all data points, please see Appendix E.

Incorporation of upgrade projects
(§ 5.2 pp 36-41)
Impact of upgrade projects
(§ 5.2 pp 36-41)

Cost function from all projects
(§ 5.2 pp 36-41)

Note: Seven data points lie outside the bounds of this chart. For all data points, please see Appendix E.
**Cost function through incremental development** (§ 5.2 pp 36-41)

- Higher proportion of costs classified as demand-related in all three functions
- Lower proportion of bulk system and regional system costs classified as energy-related
- Lower proportion of point of delivery costs classified as customer-related

### Transmission cost classification including point of delivery (§ 5.3 pp 41-42)

<table>
<thead>
<tr>
<th>Classification</th>
<th>2011</th>
<th>2014-2016</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bulk</td>
<td>Regional</td>
</tr>
<tr>
<td>Demand-Related</td>
<td>82.0%</td>
<td>82.0%</td>
</tr>
<tr>
<td>Energy-Related</td>
<td>18.0%</td>
<td>18.0%</td>
</tr>
<tr>
<td>Customer-Related</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>
2014-2016 cost functionalization and classification (§ 5.3 pp 41-42)

<table>
<thead>
<tr>
<th>Function</th>
<th>Total</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Demand</td>
</tr>
<tr>
<td><strong>2014 ISO Tariff</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulk System</td>
<td>55.2%</td>
<td>51.0%</td>
</tr>
<tr>
<td>Regional System</td>
<td>22.5%</td>
<td>19.7%</td>
</tr>
<tr>
<td>Point of Delivery</td>
<td>22.3%</td>
<td>21.3%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>92.1%</td>
</tr>
<tr>
<td><strong>2015 ISO Tariff</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulk System</td>
<td>61.2%</td>
<td>56.6%</td>
</tr>
<tr>
<td>Regional System</td>
<td>20.1%</td>
<td>17.6%</td>
</tr>
<tr>
<td>Point of Delivery</td>
<td>18.7%</td>
<td>17.9%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>92.1%</td>
</tr>
<tr>
<td><strong>2016 ISO Tariff</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulk System</td>
<td>62.0%</td>
<td>57.2%</td>
</tr>
<tr>
<td>Regional System</td>
<td>19.6%</td>
<td>17.2%</td>
</tr>
<tr>
<td>Point of Delivery</td>
<td>18.4%</td>
<td>17.6%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>92.1%</td>
</tr>
</tbody>
</table>

2014 rate design (§ 6 pp 43-44)

- Rate levels updated for 2014 projected revenue requirement and 2014 forecast billing determinants
- Rate calculations updated for 2014 cost functionalization and classification
- Cost of load shed service for import included with operating reserve costs for recovery through hourly allocation
- 1-month type of Rates XOS and XOM has been withdrawn
- Refinements to language to align with other AESO authoritative documents
- AESO has not reapplied for Rider I, Amortized Construction Contribution Rider
  - Stranded asset issue not yet resolved in Proceeding ID No. 20
2014 rate design (cont’d)
(§ 6.1-6.2 pp 44-47)

- Legislative requirements remain as in prior tariffs
  - Implementation of Rate XOM in 2013 reflects pre-existing legislative provisions which will become applicable with commercial operation of Alberta-Montana intertie
- Continue to use five rate design principles adapted from Bonbright
  - Cost causation remains primary consideration for rate design

Rate DTS: LSSi cost recovery
(§ 6.3.1 pp 47-48)

- Includes cost of load shed service for import (LSSi) in hourly allocation methodology used for operating reserve charge
  - LSSi cost in the hour allocated to loads based on Rate DTS metered energy in that hour
- Hourly LSSi costs reflect LSSi volumes contracted to ensure reliable supply to load in an hour
- Hourly allocation of costs will correlate to impacts on the hourly energy market such that load market participants will be subject to both LSSi costs and related energy market impacts in the same hours
- Allocating LSSi costs hourly will also minimize variances between LSSi costs and revenues that would otherwise require collection or refund through deferral accounts
Changes to Rate DTS levels
(§ 6.3.1 pp 47-48 and Appendix H)

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>2013 Charge</th>
<th>2014 Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bulk System Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Coincident metered demand</td>
<td>$5,033/MW</td>
<td>$7,867/MW</td>
</tr>
<tr>
<td>• Metered energy</td>
<td>$1.68/MWh</td>
<td>$1.02/MWh</td>
</tr>
<tr>
<td><strong>Local System Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Billing capacity</td>
<td>$1,243/MW</td>
<td>$2,048/MW</td>
</tr>
<tr>
<td>• Metered energy</td>
<td>$0.70/MWh</td>
<td>$0.67/MWh</td>
</tr>
<tr>
<td><strong>Point of Delivery Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Substation fraction (SF)</td>
<td>$10,926</td>
<td>$2,677</td>
</tr>
<tr>
<td>• First (7.5 × SF) MW of billing capacity</td>
<td>$7,401/MW</td>
<td>$4,321/MW</td>
</tr>
<tr>
<td>• Next (9.5 × SF) MW of billing capacity</td>
<td>$2,732/MW</td>
<td>$2,151/MW</td>
</tr>
<tr>
<td>• Next (23 × SF) MW of billing capacity</td>
<td>$1,655/MW</td>
<td>$1,487/MW</td>
</tr>
<tr>
<td>• All remaining MW of billing capacity</td>
<td>$907/MW</td>
<td>$951/MW</td>
</tr>
<tr>
<td><strong>Operating Reserve Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Hourly costs allocated on metered energy or</td>
<td>5.16%</td>
<td>7.98%</td>
</tr>
<tr>
<td><strong>Voltage Control Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Metered energy</td>
<td>$0.03/MWh</td>
<td>$0.03/MWh</td>
</tr>
<tr>
<td><strong>Other System Support Services Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Highest metered demand</td>
<td>$20/MW</td>
<td>$20/MW</td>
</tr>
</tbody>
</table>

Rate FTS: Voltage control charge
(§ 6.3.2 pp 48-49)

- Current Rate FTS voltage control charge includes two Fort Nelson-specific components
  - One component addresses transmission must-run costs before completion of phase I of the northwest Alberta transmission development
  - Second component addresses similar costs after completion of phase I of the development
- Phase I of the northwest Alberta transmission development will be completed in 2013 so the pre-completion first component has been removed from proposed Rate FTS
Rates XOS and XOM: 1 Month type
(§ 6.3.3-6.3.4 pp 49-50)

- Current Rate XOS and proposed 2013 Rate XOM include two types
  - 1 Hour type is currently available
  - 1 Month type will not be available until AESO implements an open access same-time information system (OASIS) or similar system
- AESO has not implemented and does not expect to implement an OASIS or similar system during expected term of proposed tariff
- AESO accordingly has withdrawn 1 Month types of Rates XOS and XOM
- AESO continues to consult on and develop intertie policy
  - AESO will propose new rates in future if applicable

Rider C: Deferral account adjustments
(§ 6.3.6 pp 50-52)

- Deferral account reconciliations can result in charges and refunds to individual market participants that appear large compared to aggregate deferral account balance
- Three facets of the deferral account process may lead to large individual charges or refunds
  - $/MWh base for Rider C and $/MW base for rate components
  - Timing differences between Rider C and production-month reconciliations
  - Variances from forecasts of costs and revenues
- AESO recalculated 2011 deferral account reconciliation assuming percentage base rather than $/MWh base for Rider C
  - Did not materially reduce magnitude of individual re-allocations
Rider C: Deferral account adjustments
(cont’d) (§ 6.3.6 pp 50-52)

• AESO has also not discovered changes that would reduce impacts of timing differences and forecast variances

• AESO concludes that charges and refunds to individual market participants reflect interaction of three facets discussed above

• AESO is not recommending any changes to design of Rider C in this application
  – Will monitor future deferral account reconciliations and propose changes in future tariff application, if appropriate

Rider J
(§ 6.3.7 p 52)

• Updated to reflect variances from forecasts of cost and energy

• Charge decreases $0.12/MWh and remains at that level
### Forecast billing determinants

(§ 6.4 p 53)

<table>
<thead>
<tr>
<th>DTS Billing Determinant</th>
<th>Unit</th>
<th>2014 Forecast</th>
<th>2013 Forecast</th>
<th>2012 Recorded</th>
<th>2011 Recorded</th>
<th>2010 Recorded</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coincident Demand</td>
<td>MW-months</td>
<td>97,785.8</td>
<td>94,012.3</td>
<td>88,655.4</td>
<td>88,254.4</td>
<td>85,844.9</td>
</tr>
</tbody>
</table>

#### Billing Capacity

- Total Billing Capacity: MW-months 145,317.2 139,869.4 134,217.1 132,055.5 126,634.9
- First (7.5×SF) MW: MW-months 36,595.7 35,369.4 33,306.3 33,139.7 –
- Next (9.5×SF) MW: MW-months 32,682.3 31,398.4 29,604.4 29,125.9 –
- Next (23×SF) MW: MW-months 38,444.8 36,449.0 35,362.4 34,282.9 –
- All Remaining MW: MW-months 37,594.4 36,652.7 35,944.0 35,507.1 –
- Highest Metered Demand: MW-months 119,733.2 114,942.5 109,472.2 108,656.1 105,068.8

| Metered Energy | GWh  | 61,861.5 | 59,604.0 | 55,735.8 | 55,196.0 | 52,906.4 |
| DTS Market Participants | cust-months | 5,601.0 | 5,299.0 | 5,000.4 | 4,984.1 | – |
| Pool Price | $/MWh | $48.68 | $60.47 | $64.32 | $76.22 | $50.88 |

### Bill impacts by billing capacity and load factor

(§ 6.5 pp 54-57)

- Impacts based on Rate DTS and commodity charges

<table>
<thead>
<tr>
<th>Load Factor</th>
<th>Billing Capacity (MW)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0 to &lt; 7.5</td>
<td>7.5 to &lt; 17</td>
</tr>
<tr>
<td>0% to &lt;10%</td>
<td>7%</td>
<td>6%</td>
</tr>
<tr>
<td>10% to &lt;25%</td>
<td>(7%)</td>
<td>(5%)</td>
</tr>
<tr>
<td>25% to &lt;40%</td>
<td>(16%)</td>
<td>(2%)</td>
</tr>
<tr>
<td>40% to &lt;50%</td>
<td>(24%)</td>
<td>(2%)</td>
</tr>
<tr>
<td>50% to &lt;60%</td>
<td>(12%)</td>
<td>(1%)</td>
</tr>
<tr>
<td>60% to &lt;70%</td>
<td>(6%)</td>
<td>(0%)</td>
</tr>
<tr>
<td>70% to &lt;80%</td>
<td>(10%)</td>
<td>0%</td>
</tr>
<tr>
<td>80% to 100%</td>
<td>1%</td>
<td>0%</td>
</tr>
<tr>
<td>All</td>
<td>(6%)</td>
<td>(0%)</td>
</tr>
</tbody>
</table>
Bill impact distribution
(§ 6.5 pp 54-57)

Distribution of DTS, PSC, and Commodity Bill Increases

<table>
<thead>
<tr>
<th>Percentage Increase in DTS, PSC, and Commodity Bill, 2013-2014</th>
<th>Number of PODs</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;-30%</td>
<td>18</td>
</tr>
<tr>
<td>-30% to -20%</td>
<td>11</td>
</tr>
<tr>
<td>-20% to -10%</td>
<td>20</td>
</tr>
<tr>
<td>-10% to 0%</td>
<td>152</td>
</tr>
<tr>
<td>0% to 10%</td>
<td>0</td>
</tr>
<tr>
<td>10% to 20%</td>
<td>17</td>
</tr>
<tr>
<td>20% to 30%</td>
<td>11</td>
</tr>
<tr>
<td>30% to 40%</td>
<td>12</td>
</tr>
<tr>
<td>40% to 50%</td>
<td>4</td>
</tr>
<tr>
<td>50% to 100%</td>
<td>3</td>
</tr>
</tbody>
</table>

Long-term transmission rate impact projection
(§ 6.6 pp 57-59)

- Appendix J of application provides projection of transmission costs and Rate DTS to 2031
  - Allows example billing determinants to be varied to provide a projection of specific bills for individual load characteristics
- Provides context for changes to Rate DTS over period covered by the AESO’s most recent long-term transmission plan
- The AESO is not requesting approval of transmission rate impact projection in this proceeding
  - Transmission rate impact projection has also been filed in Commission Proceeding ID No. 2421 on alternative approaches and rate treatments to recover electric transmission related investments
Projection of average transmission rate
(§ 6.6 pp 57-59)

Terms and conditions changes
(§ 7 p 60)

• Terms and conditions comprehensively restructured in 2010 tariff application
• Incremental refinements to language proposed for 2014
  – Continues alignment with other AESO authoritative documents
• Clarification of responsibilities related to system access service requests
• Additional detail on financial obligations for connection projects
• Additional provisions to clarify participant-related and system-related costs
• Maximum investment levels updated to reflect directions from Decision 2012-362
Terms and conditions changes (cont'd)  
[§ 7 p 60)

- Additional details on generating unit owner’s contributions

Alignment with authoritative documents guidelines  
(§ 7.1 pp 60-62)

- Continuation of process to align ISO tariff, ISO rules, and Alberta reliability standards
  - Subject matter that is authoritative in nature
  - Elimination of duplication
  - Shared and consolidated definitions
  - Consistent language
  - Standardized structure and form
  - Formal review processes

- Defined terms
  - 1 definition deleted
  - 11 definitions amended
  - 14 definitions added
Section 4: System access service requests
(§ 7.2 pp 62-63)

- Provisions reorganized to align with connection process
- Additional detail to reflect current AESO practice
- Additional detail on market participant responsibilities for connection proposal
  - Facility design document, including estimate of costs
  - Technical studies
  - Land and environmental impact assessments, when required
- Circumstances when AESO will complete connection studies
  - When impact on transmission system may be significant
  - When system development is planned that integrates connection project

Section 5: Financial obligations for connection projects
(§ 7.3 p 63)

- Added second figure to clarify obligations for connection projects that are not eligible for investment
  - Typically generation projects
Section 5: Financial obligations for connection projects (cont’d) (§ 7.3 p 63)

- Clarified obligations of the AESO, market participants, and transmission facility owners
  - Determination of total financial obligation by the AESO
  - Preparation of amounts and schedule for payments by TFO
  - Security and contribution transactions occur between market participant and TFO
  - Additional detail on obligations regarding cancellation costs
- Incorporates reference to section 103.3 of ISO rules, Financial Security Requirements
- Changes reflect AESO current practice

Section 8: Construction contributions (§ 7.4 pp 63-65)

- Additional information on classification of participant-related and system-related costs
- Participant-related costs include switching or transformation substation when required for connection project
Section 8: Construction contributions (cont’d)
§ 7.4 pp 63-65

• Clarification that upgrades or expansions will be classified as system-related when the existing facilities were previously classified as system-related

• Deletion of provisions regarding costs related to the advancement of planned facilities
  – AESO plans transmission system projects to accommodate forecast load and new generation capacity in accordance with section 8(a) of Transmission Regulation
  – Connection projects that result in acceleration of system projects represent normal forecast variance
  – System project schedules will be adjusted in response to actual need to connect market participants
  – The AESO considers it inappropriate to assess costs to market participants simply due to the timing of their appearance

Section 8: Maximum investment levels
§ 7.4 pp 65-67

• The AESO filed its 2012 Construction Contribution Policy Application in June 2012
  – Contribution policy principles
  – Methodology to determine point of delivery cost function
  – Methodology to determine maximum investment levels
  – Proposed investment levels to be effective July 1, 2012

• Commission issued Decision 2012-362 in December 2012 directing the AESO to refile its investment levels in this tariff application

• Commission found principles to be reasonable

• Changes to the point of delivery cost function were discussed in cost causation section of application
Section 8: Maximum investment levels (cont'd)
(§ 7.4 pp 65-67)

• Commission supported the continued use of average cost multiplier methodology

• Commission directed multiplier be determined to provide investment coverage level of approximately 60% over all connection projects

  – The AESO has determined multiplier of 0.79 provides 60% investment coverage over all 215 projects in database
Section 8: Maximum investment levels (cont’d)  
(§ 7.4 pp 65-67)

- 2014 investment levels proposed to be effective July 1, 2014

<table>
<thead>
<tr>
<th>Investment Tier</th>
<th>2013 Level</th>
<th>2014 Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation fraction (SF)</td>
<td>$52 000/year</td>
<td>$21 700/year</td>
</tr>
<tr>
<td>First (7.5 × SF) MW of contract capacity</td>
<td>$35 350/MW/year</td>
<td>$35 000/MW/year</td>
</tr>
<tr>
<td>Next (9.5 × SF) MW of contract capacity</td>
<td>$13 050/MW/year</td>
<td>$17 450/MW/year</td>
</tr>
<tr>
<td>Next (23 × SF) MW of contract capacity</td>
<td>$7 900/MW/year</td>
<td>$12 050/MW/year</td>
</tr>
<tr>
<td>All remaining MW of contract capacity</td>
<td>$4 250/MW/year</td>
<td>$7 700/MW/year</td>
</tr>
</tbody>
</table>

Section 9: Changes after energization  
(§ 7.5 pp 67-68)

- Additional clarity on timing of payment and refund of adjustments to construction contributions
  - Market participant must pay adjustment at least 30 days prior to change in contract capacity or investment term when construction of facilities are not required
  - Market participant must pay adjustment within 30 days of request in all other circumstances
  - Transmission facility owner must refund adjustment within 30 days of change in contract capacity or investment term when construction of facilities are not required
  - Transmission facility owner must refund adjustment within 90 days after Commission issues permit and licence
  - Transmission facility owner must refund adjustment within 90 days after ISO determines amount in all other circumstances

65

66
Section 9: Waivers of payment in lieu of notice (§ 7.5 pp 68-69)

• In Decision 2011-275 the Commission directed the AESO to report on waivers of payment in lieu of notice permitted under subsection 5(6) of section 9 of the ISO tariff, added during 2010 tariff proceeding

• The AESO reported it had received two requests for waivers
  – One received in 2011 resulted in a waiver of $55,000 for a 10 MW contract capacity reduction
  – One received in 2012 for an 8.8 MW contract capacity reduction is still being assessed for eligibility

• The AESO is not proposing any further changes to the provisions for waiver of payment in lieu of notice

Section 10: Generating unit owner’s contribution (§ 7.6 pp 69-70)

• Additions to address payments and refunds in circumstances not clearly addressed in current provisions

• When multiple generating units exist at a single point of supply, contract capacity and contributions are allocated to individual generating units based on each unit’s maximum capability

• When contract capacity varies over the term of a Rate STS contract, contributions are based on the highest 12 months of contract
  – System capacity would not be planned to accommodate generation in place for less than one year
Section 10: Generating unit owner’s contribution (cont’d) (§ 7.6 pp 69-70)

• When changes to contract capacity occur after a project is energized, an additional generating unit owner’s contribution is calculated for any material increases to contract capacity

• AESO removed requirements for a generating unit owner to self-report performance
  – AESO has found that self-reporting is not an effective approach to assessing performance data

• Generating unit owner’s contributions must be paid at least 30 days before the start of brushing or other vegetation management activities
  – Aligns with Transmission Regulation requirement that contribution be paid before “commencement of construction”
  – Corrects later due date implied in current tariff

Appendix B: Construction commitment agreement proforma (§ 7.8 p 70)

• Revision of construction commitment agreement proforma to ensure alignment with the proposed section 5 of the tariff

• Revisions not yet complete and will be filed as an addendum to the application as soon as possible
Responses to directions
(§ 8 pp 71-73)

• Application included responses to directions from several prior decisions

• Decision 2010-606
  – Conduct an updated Transmission Cost Causation Study
  – Consider anticipated transmission system additions in forecast
  – Utilize the most recent AESO long term transmission plan
  – Revise Rate FTS
  – Investigate firm export rates
  – Review potential changes to Rider C

• Decision 2011-040
  – Investigate Rider C to minimize the need to re-reconcile

Responses to directions (cont’d)
(§ 8 pp 71-73)

• Decision 2010-274
  – Report on PILON waiver requests
  – Discuss any further required revisions

• Decision 2012-362
  – File the proposed changes to the average cost function in the next tariff application
  – Address the concerns in the Decision and included in the next tariff application

• Decision 2013-034
  – Consider Commission concern about repeated reconciliations of deferral account years
Appendices (filed separately)

A AESO Board Decision 2013-BRP-001
B AESO 2013 Business Plan and Budget Proposal
C 2013 Rate Calculations
D Proposed 2013 Tariff Update
E Transmission Cost Causation Study
F Transmission Cost Causation Workbook
G Point of Delivery Cost Function Workbook
H 2014 Rate Calculations
I 2014 Bill Impact Analysis
J Transmission Rate Impact Projection
K 2014 Contribution Policy Investment Levels Workbook

Appendices (cont’d) (filed separately)

L Proposed 2014 Tariff
M Defined Terms Used in ISO Tariff
N Comparison of Proposed and Current Terms and Conditions
O Blackline Comparison of Proposed and Current Definitions
Questions and discussion

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- Tariff application on AESO website at www.aeso.ca ► Tariff ► Current Applications ► 2014 Tariff

- Tariff application on Commission website at www.auc.ab.ca as Proceeding ID No. 2718
Thank you