


<p><b>AESO 2010 ISO Tariff Technical Meeting</b></p> <p>John Martin, Director, Tariff Applications Lee Ann Kerr, Manager, Tariff Applications Raj Sharma, Senior Tariff Analyst Arnie Reimer, consultant to AESO March 23, 2010 — Calgary, Alberta</p>	<p>Reliable <b>Power</b></p> <p>Reliable <b>Markets</b></p> <p>Reliable <b>People</b></p>
 	

<p><b>Agenda</b></p>	
<ul style="list-style-type: none"><li>• Introduction slides 1-3</li><li>• Summary and background slides 4-6</li><li>• Revenue requirement slides 7-10</li><li>• Transmission O&amp;M cost study slides 11-17</li><li>• Rate design slides 18-38</li><li>• Terms and conditions slides 39-79</li><li>• Future applications slides 80-82</li><li>• Schedule slide 83</li><li>• Discussion slides 84-85</li></ul>	
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## Meeting Objectives



- Familiarity with application contents
  - No formal break during presentation
  - Please get refreshments or stretch legs as needed (but quietly)
- Understanding of AESO's proposals for 2010 ISO tariff
  - Rates, riders, and terms and conditions which have no material changes from current tariff are not included in this presentation
- Expectations for balance of this proceeding
- Responses to questions about application and proposals
  - Questions only for clarity
  - More detailed information and rationale should be addressed through information requests

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## Application Summary



- Comprehensive tariff application for 2010 forecast year
  - Filed on March 5, 2010
  - Additional appendices and some revisions on March 16, 2010
- Rates and riders to be charged for system access service
- Terms and conditions that apply to system access service
- Discussion of future applications and responses to directions
- Eleven supporting appendices
  - Two studies and five Excel workbooks
  - Per-POD bill impact analysis
  - Comparison of proposed and current terms and conditions

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## Relief Requested

§ 1.3, p 8



- Confirmation that entire revenue requirement is subject to deferral account treatment
- Approval of proposed tariff including rates, riders, terms and conditions, and tariff appendices
- Continued use of Rider C and annual deferral account reconciliations to ensure recovery of all incurred costs
- Approval of an approach to update rate and investment levels in annual filings
- Acceptance of responses to outstanding directions
- Effective date no earlier than 90 days after decision
  - Except contribution policy sections retroactive to January 1, 2010

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## Application Background

§ 1.1, pp 5-6



- Last comprehensive tariff application filed on November 3, 2006 for 2007 forecast year
  - 2007 tariff became effective on August 1, 2008
  - Subsequent R&V removed O&M charge from standard facilities
- Rates update filed on March 13, 2009 for 2009 forecast year
  - 2009 rates became effective on October 1, 2009
- Proposals in 2010 application further develop and refine the AESO's tariff
  - respond to directions in prior decisions
  - reflect consideration of stakeholder input provided in consultation
  - address other matters considered appropriate by the AESO


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**2010 Revenue Requirement**  
§ 2, p 10



Cost Component	2010 Forecast	2009 Forecast	Increase (Decrease)	
	\$ 000 000	\$ 000 000	\$ 000 000	%
Wires	\$648.4	\$523.7	\$124.7	23.8%
Ancillary Services	144.3	282.2	(137.9)	(48.9%)
Losses	173.6	238.0	(64.4)	(27.1%)
Administration	79.4	80.0	(0.6)	(0.7%)
<b>Revenue Requirement</b>	<b>\$1,045.8</b>	<b>\$1,123.9</b>	<b>(\$78.1)</b>	<b>(7.0%)</b>

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- 2010 Revenue Requirement (cont'd)**  
§ 2.1, pp 10-14
- 
- AESO Board-approved ancillary services costs, losses costs, and administration costs
    - AESO consulted with stakeholders through Budget Review Process
    - Must be considered as “prudent” by the Commission unless an interested person satisfies the Commission otherwise
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## 2010 Revenue Requirement (cont'd)

§ 2.2, pp 14-17



- Forecast wires cost reflect status of each TFO's 2010 TFO tariff application
  - 2010 TFO tariff costs if final decision issued by Commission
    - ATCO Electric, TransAlta
  - 2010 compliance filing costs of initial decision issued by Commission and compliance refiling submitted by TFO
    - AltaLink, Red Deer
  - 72% of applied-for 2010 TFO tariff increase if initial decision not issued or if compliance refiling not yet submitted
    - EPCOR, Lethbridge, FortisAlberta (farm transmission)
  - Most recently-approved TFO tariff if TFO has not yet applied for 2010 tariff
    - ENMAX

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## Stakeholder Consultation

§ 3, pp 20-22



- Initial meetings with individual stakeholders on scope
- Three general stakeholder meetings to provide information on the development of tariff application proposals
- Nine small working groups to examine specific topics
- Information from other consultation processes
  - AltaLink 2008 recommendations on AESO's contribution policy
  - Connection process redesign
  - Interties policy
  - Remedial action schemes in transmission system planning
  - Transition of Authoritative Documents ("TOAD") project
  - Wind forecasting service cost recovery

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# AESO 2010 ISO Tariff Application Technical Meeting Appendix C - Transmission Operating and Maintenance Cost Study

March 23, 2010  
Arnie Reimer P. Eng.  
PS Technologies

## Background

- Cost Causation Study with 2007 GTA based on capital costs
- Operating and Maintenance costs assumed to track capital costs
  - Functionalization on Voltage, Economics and MW-kM
  - Classification on incurrence of costs

## Background

- Capital Related Costs – Table 4-2 Application

Capital Related Costs	Bulk System	Local System	POD	Totals
Demand Related	34.0%	14.3%	17.6%	66.0%
Energy Related	7.7%	3.0%	0.3%	11.0%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
<b>Totals</b>	<b>41.7%</b>	<b>17.4%</b>	<b>40.9%</b>	<b>100.0%</b>
<b>Classification of Costs by Function</b>				
Demand Related	81.5%	82.5%	43.1%	
Energy Related	18.5%	17.5%	0.7%	
Customer (POD)	0.0%	0.0%	56.2%	

## Separation of Capital and Non Capital Costs

- Costs first sorted as Capital or Non Capital Costs
  - Capital Costs include depreciation, debt servicing, return, and income taxes
  - Non capital costs defined as those costs not closely tied to capital investment and those where management has some discretion
- A review of costs show that some costs considered non capital exhibit the characteristics of capital related costs
  - Linear taxes (Taxes other than Income)
  - Structure Payments
  - Capital Related Revenue Offsets
- Capital Costs account for 71% of RR, Non Capital – 29%

## Non Capital Costs (29% of RR)

- Non Capital Costs sorted as:
  - Operating and Maintenance (O&M)
    - O&M costs linked to operation and maintenance of the electric transmission system
  - General and Administration (G&A)
    - G&A costs linked to running the business

## Functionalization and Classification

- Functionalization of costs on the basis of incurrence
  - Brushing, by voltage level, Operations by elements
- Operations and Maintenance can not be reliably classified
  - Operations and Maintenance work is completed on facilities to ensure that they operate reliably and efficiently to meet their original design specifications
- Operations and Maintenance is classified on the same basis as capital
- One exception being fuel cost within transmission which is classified as energy.

**Results – Weighting of Capital and O&M  
71% Capital, 29% Non Capital  
Table 4-3 and 4-4 of Application**

<b>O&amp;M Classification is used for All Non Capital Costs</b>				
<b>Breakdown of Non Capital Costs</b>	<b>Bulk System</b>	<b>Local System</b>	<b>POD</b>	<b>Totals</b>
Demand Related	13.2%	23.8%	18.4%	55.4%
Energy Related	3.0%	8.7%	8.8%	20.5%
Customer (POD)	0.0%	0.0%	24.0%	24.0%
<b>Totals</b>	<b>16.2%</b>	<b>32.5%</b>	<b>51.3%</b>	<b>100.0%</b>
<b>Breakdown of Capital Costs (2007 GTA)</b>	<b>Bulk System</b>	<b>Local System</b>	<b>POD</b>	<b>Totals</b>
Demand Related	34.0%	14.3%	17.6%	66.0%
Energy Related	7.7%	3.0%	0.3%	11.0%
Customer (POD)	0.0%	0.0%	23.0%	23.0%
<b>Totals</b>	<b>41.7%</b>	<b>17.4%</b>	<b>40.9%</b>	<b>100.0%</b>
<b>Weighted Capital and Non Capital</b>	<b>Bulk System</b>	<b>Local System</b>	<b>POD</b>	<b>Totals</b>
Demand Related	28.0%	17.0%	17.9%	62.9%
Energy Related	6.4%	4.7%	2.7%	13.8%
Customer (POD)	0.0%	0.0%	23.3%	23.3%
<b>Totals</b>	<b>34.4%</b>	<b>21.7%</b>	<b>43.9%</b>	<b>100.0%</b>

**Rate DTS**  
§ 4.3.1, p 32



- New usage (\$/MWh) component of Rate DTS point of delivery charge
  - Reflect classification of fuel for isolated generation as usage-related in *Transmission Operating and Maintenance Cost Study*

**Rate DTS (cont'd)**

§ 4.3.1, pp 33-34



- Classify balance of point of delivery costs based on *POD Cost Function Update*
  - *Update* adds 17 projects to connection project dataset
  - *Update* uses composite inflation index instead of Alberta consumer price index to escalate costs to 2010
  - *Update* uses total project costs and a multiplier of 1.06 to yield same total investment as would result from using projects' standard facilities costs and a multiplier of 1.15

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**Rate DTS (cont'd)**

§ 4.4, pp 35-38



- Allocate operating reserve costs on an hourly basis to eliminate operating reserve deferral account balance
  - Allocated by metered energy
  - If calculation cannot be performed for any reason then charge will be estimated as metered energy  $\times$  pool price  $\times$  3.12%

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## Rate FTS

§ 4.5.2, pp 41-42



- Eliminate interim refundable Fort Nelson Rider H
- Primary driver for Rider H was increased forecast for TMR service caused by requests from BC Hydro for increased contract capacity at Fort Nelson
- Northwest Alberta transmission development is expected to keep TMR requirements at or below the levels required in recent years
- Conditions affecting system access service to Fort Nelson will remain similar to those that existed when Rate FTS was initially developed

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## Rate FTS (cont'd)

§ 4.5.3, p 43



- Allocate Rainbow area TMR generation costs *after* completion of northwest Alberta development on an hourly basis using incremental Fort Nelson and Rainbow area hourly loads
- Northwest Alberta transmission development was forecast to eliminate the requirement for TMR generation in the Rainbow area for forecasted load of 25 MW for Fort Nelson and 105 MW for Rainbow area
- If total Rainbow area load exceeds 130 MW then TMR cost will be allocated based on the share of incremental load growth over the above-mentioned forecast load

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## Rate FTS (cont'd)

§ 4.5.3, pp 43-44



- Allocate *incremental* Rainbow area TMR generation costs *prior* to completion of northwest Alberta development on an hourly basis using incremental Fort Nelson and Rainbow area hourly loads
- Method is similar to that proposed for allocation of TMR generation costs after the northwest Alberta development is complete
- As Rainbow area load up to 130 MW can be supported by three TMR generators, incremental TMR generation would be the dispatch of a fourth TMR generator in the Rainbow area

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## Rate FTS (cont'd)

§ 4.5.4, pp 44-46



- Allocating *future* capital costs in northwest Alberta using incremental Fort Nelson and northwest Alberta forecast load
- Ensures comparable basis for various options available for serving additional load at Fort Nelson
- Transmission system developments, by their nature, generally accommodate regional needs over multiple areas and sharing of capital cost is appropriate
- Northwest Alberta transmission development was based on a need analysis that forecast a load of 1,310 MW in the northwest area in 2014-2015, which included 25 MW of load in Fort Nelson and 1,285 MW of load in northwest Alberta

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## Rate FTS (cont'd)

§ 4.5.4, pp 46-47



- Recover any capital cost allocated to Fort Nelson, BC through a levelized charge incorporated into the existing local system charge in Rate FTS
- Determine using capital structure, return on equity, cost of debt, and income tax rate applicable to the transmission facility owner at the time the development was constructed
- Local system charge of Rate FTS is higher of local system charge of Rate DTS and charge specific to Fort Nelson calculated as described above
- Levelized charge would be approved through an AESO application to the Commission

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## Rate FTS (cont'd)

§ 4.5.4, p 47



- Treat any unrecovered capital cost attributed to Fort Nelson, BC similarly to adjustments to construction contributions resulting from a termination of system access service under section 9 of terms and conditions
- If BC Hydro terminates system access service, recovery of any capital costs allocated to Fort Nelson (including the cost of original ATCO Electric line) will be adjusted based on revised duration of system access service rather than original recovery period
- BC Hydro would be required to pay any resulting increase in the levelized charge above what was actually paid, without interest

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## Rate DOS

§ 4.6, pp 47-49



- Combine three demand opportunity service rates into single Rate DOS with three types of service
- Allocate fixed components of Rate DTS bulk and local system charges 100% and 1200% respectively to Rate DOS Term
  - Same result as more complicated allocation approved in 2007 tariff application and 2009 rates update

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## Rate XOS

§ 4.7.1, pp 50-51



- Combine two export opportunity service rates into single Rate XOS with two types of service
- Allocate fixed components of Rate DTS bulk and local system charges 20% to Rate XOS 1 Hour and 30% to Rate XOS 1 Month
  - Same result as more complicated allocation approved in 2007 tariff application and 2009 rates update

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## Rate XOS (cont'd)

§ 4.7.1, pp 51-52



- Allocate 32% of the Rate DTS operating reserve charge to exports
  - Analysis based on 2008 data
- When contingency reserve requirement is established by the single largest generator contingency, no operating reserves are allocated to export service
- When contingency reserve requirement is established by the sum of 5% of hydro and wind generation and 7% of thermal generation, operating reserves are allocated proportionately to export volumes and domestic load volumes
  - Domestic loads always allocated the value of single largest generator contingency at a minimum

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## Future Export Rates

§ 4.7.2, p 52



- Propose additional export rates either in a standalone export and import rates application or in a future tariff application
- AESO consulted with stakeholders on export and import services as well as on intertie policy in general, including such matters as legislative requirements, inter-jurisdictional “seams”, and implementation complexity
- Consultation not yet concluded
  - Intend to continue development of export and import services

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## Rate PSC

§ 4.9, pp 53-54



- Determine primary service credit as percentage of components of Rate DTS point of delivery charge:
  - 79% of fixed tier,
  - 79% of first three demand tiers,
  - 100% of fourth demand tier, and
  - 79% of the energy component
- Calculated as average ratio of substation-related cost to sum of substation-related cost and line-related cost for recent connection projects

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## Rate PSC (cont'd)

§ 4.9, pp 54-55



- Make Rate PSC mandatory for a market participant whose connection does not include conventional transformation facilities owner by a TFO
- Rate PSC being an option creates an opportunity for cross-subsidizing line facilities

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## Deferral Account Adjustment Rider C § 4.13, pp 56-57



- Discontinue working capital deficiency/surplus Rider B
  - Rider B has not been used and is inferior to Rider C
- Include only transactions settled after January 1 in calculation of Rider C
  - Year-end balance would be settled through deferral account reconciliation application
- Prepare and publish Rider C at least 30 days before start of calendar quarter
- Rider C rewritten to provide clarity, certainty, consistency, and transparency
  - For example, interest will not be added or deducted unless ordered by the Commission

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## Amortized Construction Contribution Rider I § 4.16, pp 58-62



- Structure to mirror treatment of costs as TFO rate base
  - Financial benefits to TFO are fully recovered through the amortized contribution payment
  - Offer as an option for market participants under both Rate DTS and Rate STS
  - Reflect capital structure, debt rate, return on equity, and income tax rate applicable to TFO
- Rider I must not increase risk of stranded assets and increased costs for other market participants
  - AESO may deny request for or rescind an existing Rider I
  - Rider I will be available only after commercial operation
  - Add a risk premium of 0.1% to discount rate used to calculate Rider I payments

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## Wind Forecasting Service Cost Recovery Rider J § 4.17, pp 62-64



- Recover cost of implementing a centralized wind forecasting service in Alberta
  - Recovers costs arising from wind forecasting service contract
- Costs over four years (2010-2013) recovered over wind production over same period
  - Costs generally constant while production increases over period
  - Greater amount of costs recovered in later years
- Escalate rider charge by 10% each year
  - Starts at \$0.10/MWh in 2010 and escalates to \$0.13/MWh in 2013

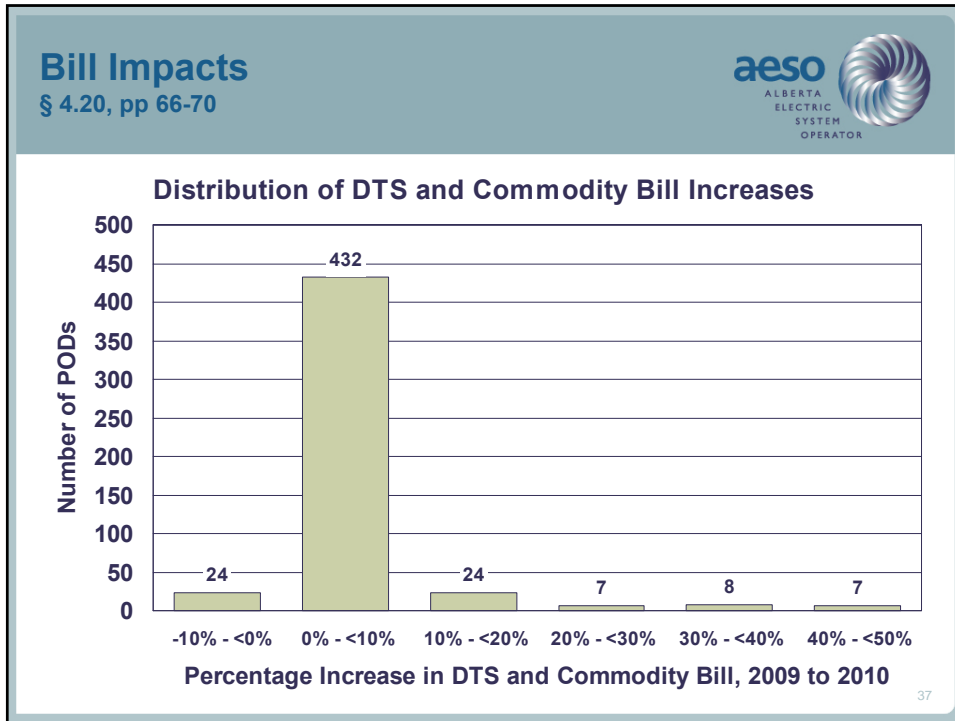
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## 2010 Forecast Billing Determinants § 4.19, pp 65-66



- Based on 2010 load forecast in AESO's *Future Demand and Energy Outlook (2009-2029)*
- Number of DTS market participants increased by about 1%
- Demand and energy billing determinants decreased between about 1% and 3% compared to 2009 forecast
- Billing capacity determinants shifted to lower tiers
  - Highest tier (above 40 MW) decreased by about 15% compared to 2009 forecast
  - Lower tiers increased between about 1% to 4% compared to 2009 forecast

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- Rate Calculations**  
§ 5, pp 71-90
- 
- Same general methodology and format as 2007 tariff application and 2009 rates update
    - Cost functionalization and classification updated
    - POD cost function updated
  - Tables with formulas provided as separate Microsoft Excel workbook
  - Bill impact estimator included as last table in workbook
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## Terms and Conditions

§ 6, pp 91-94



- **Comprehensively reorganize terms and conditions**
  - Implement structure and approach sustainable in context of AESO's authoritative documents
  - Provide stability and certainty for market participants
- **Reorganization does not change content or intent**
  - Proposed to improve clarity, certainty, consistency, and transparency
- **Also propose several content changes**
  - Reflect new connection model
  - Revise financial obligations to a “staged” approach
  - Add detail to determination of construction contributions
  - Include DOS authoritative content from other documents

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## Tariff Changes Related to TOAD

Project § 6.1, pp 94-96



- **Rewrite tariff in accordance with TOAD project guidelines**
  - Structure of authoritative documents
  - Standard conventions for interpretation
  - General approach to language in authoritative documents
- **Remove four articles as content contained in other authoritative documents**
  - Article 12 on UFLS (covered in rate and Alberta reliability standards)
  - Article 18 on limitation of liability (covered in legislation)
  - Article 19 on dispute resolution (covered in ISO rules)
  - Article 20 on confidentiality (covered in ISO rules)
- **Remove technical content covered in technical standards**

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## Connection Process Redesign

§ 6.2, pp 96-97



- Market participants will become more engaged and more accountable for progress and completion of connection projects
- Connection process redesign changes primarily affect:
  - section 4 on system access service requests,
  - section 5 on financial obligations, and
  - section 8 on construction contributions

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## Definitions

§ 6.3, pp 97-99



- Move tariff definitions to *Consolidated Authoritative Documents Glossary* with other definitions from all AESO authoritative documents
  - If term used in just one section of a single document, it will be defined within that section and will not be included in the glossary
- Delete 32 definitions no longer used
- Delete 13 definitions referring to a rate, tariff section, or document
- Embed 7 definitions with rate or section of tariff
- Replace 12 definitions with other defined terms
  - For example, “TFO” became “**owner of transmission facilities**”

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## 1: Applicability and Interpretation

§ 6.4, p 100



- Align applicability and interpretation provisions in tariff with similar provisions in other authoritative documents
- Replace references to “customer” in tariff with “market participant”

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## 2: Provision of and Limitations to System Access Service § 6.5, p 101



- Consolidate provisions from three current Articles
  - Provision of system access service from Article 3
  - Metered demand limitations from Article 13
  - Service interruptions and force majeure from Article 17
- Remove references to reliability standards
  - Alberta reliability standards have own applicability provisions

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### 3: System Access Service Connection Requirements § 6.6, pp 101-102



- Use term “connection” rather than “interconnection”
  - Interconnection now refers to interties with transmission systems in other jurisdictions
- Replace listing of technical requirements with reference to AESO website
- Delete requirements for generating units to install PSS and AVR
  - Provisions contained in technical connection requirements

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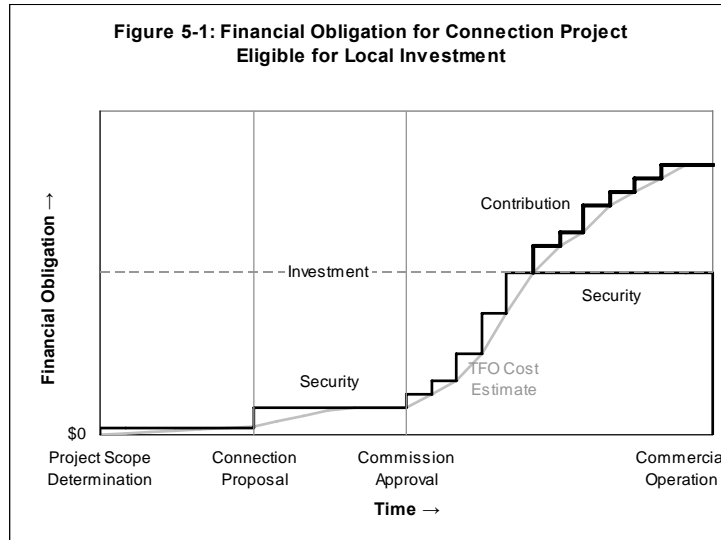
### 4: System Access Service Requests § 6.6, pp 101-102



- Provide greater clarity on roles and responsibilities of market participants, the AESO, and owners of transmission facilities
  - Market participants may choose to coordinate work and perform studies themselves or through transmission facility owner or AESO
- Eliminate application fee for connection projects
- Main differentiation is whether requests require construction of new transmission facilities or not
  - No differentiation between distribution system owners and others, and between service at new rather than existing point of delivery
- Require market participant to meet certain critical requirements for project to remain active in queue
  - Essentially same as provisions in current Article 13.2

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**5: Financial Obligations for Connection Projects § 6.8, pp 103-106**



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**5: Financial Obligations for Connection Projects (cont'd) § 6.8, pp 103-106**



- Financial obligation met through:
  - security for costs covered by investment; and
  - contribution for costs above available investment
    - Investment not available under Rate STS
    - All financial obligations for Rate STS projects met by contribution
- Distribution system owners not required to provide security
- Security and contribution always provided in advance of costs actually being incurred by the TFO
  - If security or contribution not provided when due, all work related to connection project is suspended
- Provide additional detail and transparency on treatment of cancellation of connection projects

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## 6: Metering

§ 6.9, pp 106-107



- Compliance with *AESO Measurement System Standard* is primary requirement
- Similar provisions in current tariff
- Delete provisions which are duplicated in *AESO Measurement System Standard* or *Transmission Regulation*

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## 7: Provision of Information by Market Participants § 6.10, p 107



- Update for clarity
- Delete requirement to provide “Metering Equipment information outlined in Appendix A” as well as Appendix A itself, as both are addressed in *AESO Measurement System Standard*
- Revise forecast information to be provided in response to AESO request, no more than once in a 12-month period
  - Consistent with current AESO practice

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## 8: Construction Contributions for Connection Projects § 6.11, pp 107-110



- Three new sections created from Article 9
- Section 8 covers construction contributions for connection projects
  - Address connection projects where construction of new facilities is required
- Update to increase clarity and reduce subjectivity for market participants

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## 8: Construction Contribution Policy Principles § 6.11, pp 107-110



- Recent proceedings established several contribution policy principles
- Contributions should relate only to the local connection costs for a particular system access service
- Policy should send appropriate price signals for siting
- Excessive investment would provide incentives to pursue higher standards of facilities than required
- Maximum investment should be below a level representing the incremental revenues expected from the connection
- Investment should be set with regard to the connection costs and reflect acceptable standards and service

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## 8: Construction Contribution Policy Principles (cont'd) § 6.11, pp 107-110



- Connection service and standards may change over time
- Cost, not revenue, is appropriate starting point for establishing contribution policy
- Economies of scale should be reflected in investment function
- Dual-use formula should be maintained
- Rate DTS POD charge function should be the basis for the investment function
- Distribution system owners and direct-connected market participants should be treated comparably

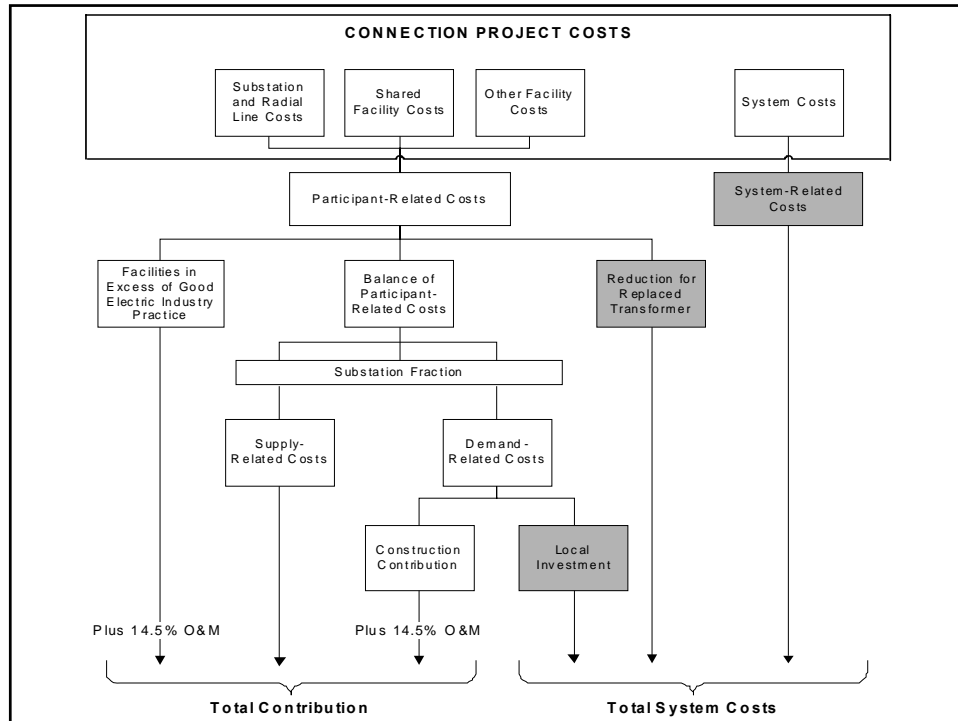
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## 8.2: Connection Costs § 6.11.1, pp 110-112



- Explicit identify that costs for a connection project will include those related to facilities required to meet the market participant's forecast load or generation and the market participant's reliability and operating requirements
- Only include costs of facilities owned by a TFO
- Only include those costs required to provided a new system access service or improve an existing system access service are considered "connection costs"
- Consistent with current AESO practice

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### 8.3: Participant- and System-Related Costs § 6.11.2, pp 113-114



- Significant detail on participant- and system-related costs
- Participant-related costs include costs associated with:
  - Connection substation including in-out line configurations
  - New radial lines
  - Share of existing facilities constructed to connect another customer
  - Line moves, communication enhancements, breakers, etc.
- System-related costs include costs associated with:
  - Looped transmission facilities that increase number of paths
  - Relocation of existing looped facilities
  - Installation of capacitor banks or shunt reactors
  - Transmission facilities included in long-term plan

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## Removal of “AESO Standard Facilities” § 6.11.3, pp 114-116



- Eliminate time and resources expended by all parties on evaluating, debating, and estimating costs for facilities that would not ultimately be constructed
- “Standard facilities” definition does not accurately reflect past practice
  - Two-thirds of all PODs are connected through two or more lines
  - Half of all PODs contain more than one transformer
- Better alignment today between cost of facilities, investment levels, and AESO rates
- Investment is most often limited by maximum amount available based on contract capacity, not by standard facilities determination
- Aligns with implementation of new connection model

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## 8.4: “Good Electric Industry Practice” § 6.11.3, pp 114-116



- Introduce ability of TFO to deem facilities to be “in excess of those required by good electric industry practice”
- Provide mechanism to prevent abuse of removal of concept of “standard facilities”
- Good electric industry practice is “the standard of practice attained by exercising that degree of knowledge, skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking in the same or similar circumstances, including determining what is reasonable in the circumstances having regard to economic considerations”

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## 8.5: Valuation of Facilities

§ 6.11.4, pp 116-117



- Formalize that equipment used for a connection project will be valued at replacement cost new (RCN)
- Formalize reduction in cost for a project if transformer is removed and replaced with a larger transformer
  - Based on RCN value of existing transformer that is removed
- Calculation is done strictly for the purpose of determining contribution
  - Has no effect on TFO asset accounting values
- Consistent with current AESO practice

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## 8.6: Allocation of Costs to Market Participants

§ 6.11.5, p 117



- Continue provisions in current tariff which determine demand-related and supply-related costs
- Update to rely on a market participant's substation fraction
- Substation fraction means "the share of a substation's capacity attributable to a market participant under Rate DTS or Rate STS, calculated by dividing the contract capacity of the individual system access service by the sum of all contract capacities of all system access services provided at the same substation under Rate DTS and Rate STS"

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## 8.7: Determination of Construction Contribution § 6.11.6, p 117



- Formalizes that contribution is based on tariff that is in effect at the time the Commission issues permit and licence for the connection project

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## 8.8: Determination of Local Investment § 6.11.7, pp 117-121



- Update and revise local investment determination currently described in Article 9.6
- Data analysis provided in *2010 POD Cost Function and Investment Level Update Recommendations*
  - Uses a composite inflation index to update project costs in the determination of the POD cost function
  - Uses updated recent project costs to develop the composite price index and the primary service credit
  - Develops a total cost multiplier of 1.06 to give the same total investment as a standard cost multiplier of 1.15


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**8.8: Maximum Local Investment Amounts** § 6.11.7, pp 117-121



Tier	Investment for Service Under Rate DTS	Investment for Service Under Rate DTS with Rate PSC
Substation fraction (for new points of delivery only)	\$51 050/year	\$10 720/year
First (7.5 × substation fraction) MW of contract capacity	\$34 650/MW/year	\$7 275/MW/year
Next (9.5 × substation fraction) MW of contract capacity	\$12 800/MW/year	\$2 690/MW/year
Next (23 × substation fraction) MW of contract capacity	\$7 750/MW/year	\$1 630/MW/year
All remaining MW of contract capacity	\$4 200/MW/year	\$0/MW/year

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- 8.8: Determination of Local Investment** (cont'd) § 6.11.7, pp 117-121
- 
- Specify that investment for an increase in load will be based on the change in contract capacity since the most recent change in construction contribution
  - Remove net present value calculation for investment applicable to staged increases and decreases to load
    - Per year and per MW structure of maximum investment level no longer requires a present value calculation.
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## 8.9: Operations and Maintenance

§ 6.11.8, pp 121-122



- Implement revised operations and maintenance charge of 14.5%
  - Based on analysis in *Transmission O&M Cost Study* provided as Appendix C to application
- To align with removal of concept of “standard facilities”, apply operations and maintenance charge to all demand-related costs above investment level determined for a project

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## 8.11: Discount Rate

§ 6.11.10, pp 122-123



- Update to make more generally applicable to TFOs in Alberta
- Incorporate equity ratio variable to represent equity ratio approved by Commission for each TFO
- Adjust tax rate to zero when discount rate formula is used for TFO that does not pay income tax

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## 9: Changes to Service After Energization § 6.12, pp 123-124



- Consolidate information on events that may result in adjustments to construction contributions
- Provide detail on allocation of costs of shared facilities
- First, cost of shared transmission line is allocated among substations based on the greater of Rate DTS or Rate STS contract capacities at each substation, averaged over 20 years following commercial operation
- Second, cost of shared facilities at a substation serving two or more market participants is allocated among those market participants based on the substation fraction for each service at the substation, averaged over 20 years

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## 9.4: Determination of Construction Contribution § 6.12.3, p 125



- Formalize that adjustment is determined under contribution provisions in tariff applicable to the project when it was originally constructed
- Adjustments occur without interest
- Limit adjustments to construction contributions to \$10,000 or more

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## 9.5: Reductions or Terminations of Contract Capacity § 6.12.4, p 125



- Continue provisions in existing tariff
- Add detail to clarify provisions around obligations related to reductions or terminations
  - Add detail on calculation of payment in lieu of notice
- Note circumstances under which the AESO may waive or reduce requirements for payment in lieu of notice
- Require payments of contribution adjustments in 30 calendar days

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## 10: Generating Unit Owner's Contribution § 6.13, pp 125-126



- Change terminology to “generating unit owner’s contribution” from “system contribution”
  - Align with terminology in *Transmission Regulation*
- Revise to accommodate TOAD project guidelines for authoritative documents

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## 12: Demand Opportunity Service

§ 6.15, p 126



- Consolidate authoritative content from other documents into terms and conditions
  - From *Demand Opportunity Services Business Practices*
  - From AESO Operating Policies and Procedures OPP 507
- Improves clarity of DOS processes by including:
  - eligibility and pre-qualification for DOS,
  - commercial eligibility criteria,
  - transaction requests,
  - recallable service, and
  - effect of disqualification for DOS

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## 13: Financial Security, Billing and Payment Terms

§ 6.16, pp 126-127



- Update and clarify existing provisions
- No longer require owners of regulated electric distribution systems to provide financial security for monthly billing for system access service charges
  - Reasons for not requiring security for connection projects equally applicable

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## 14: Peak Metered Demand Waivers

§ 6.17, p 127



- Update and clarify existing provisions
- Describes how requests for peak metered demand waivers are made by market participants and determined by the AESO
  - Authoritative content currently exists in AESO Operating Policies and Procedures OPP 1202
- Extend submission deadline for peak metered demand waiver requests to seven business days
  - Currently three business days

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## 15: Miscellaneous

§ 6.18, pp 127-128



- Update and clarify existing provisions
- No longer attempt to make system access service agreements binding on subsequent ISOs
- SPRDA generating units are exempt from provisions of Rate STS; move exemption to Rate STS itself
- Add provision to allow mutually-agreeable termination of system access service or other agreement under tariff

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## Regulated Generating Units (Appendix A) § 6.19, p 128



- Relocate from rate appendix
- Correct some regulated generating unit MW values based on detailed review of values in PPAs
- Delete regulated generating units with base life years earlier than 2010

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## Agreement Proformas (Appendix B) § 6.20, p 128



- Extensively revise system access service agreement proformas to include information specific to individual services
- Include provisions commonly used in individual service agreements and not already addressed in the terms and conditions

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## Deleted Articles

§ 6.22, pp 128-130



- Article 12 on under-frequency load shedding
  - Provisions addressed in Rate UFLS and Alberta reliability standards
- Article 17 on service interruptions and force majeure
  - Relocate provisions to section 2 of terms and conditions
  - Remove requirement that AESO provide six months' written notice before interrupting system access service to perform construction, commissioning, and facility testing activities
- Article 18 on limitation of liability
  - Provisions duplicate from subsections 90(2), (3), and (4) of *Electric Utilities Act*
- Article 19 on dispute resolution
  - All disputes addressed under section 103.2 of ISO rules

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## Deleted Articles (cont'd)

§ 6.22, pp 128-130



- Article 20 on confidentiality
  - All confidentiality rights and obligations will be addressed under section 103.1 of ISO rules
- Appendix A on metering equipment information
  - Requirements are addressed in *AESO Measurement System Standard*

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## Proposed ISO Tariff

§ 7, pp 131-258



- Provided as separate document
- Includes rates, riders, terms and conditions, and appendices
- Appendix K provides comparison of provisions in proposed tariff to corresponding provisions in current tariff

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## ISO Tariff Updates

§ 8.1, pp 259-261



- Propose to file comprehensive tariff applications every three years or potentially less frequently
- Adjusting rates and investment levels in intervening years through tariff update applications
  - Use forecast wires costs, AESO Board-approved costs, and forecast billing determinants
  - Calculate rate levels using rate calculations approved in most recent comprehensive tariff application
  - Update composite inflation index and use to adjust investment levels

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## Other Future Tariff Applications

§ 8.3-8.3, pp 261-264



- Update *Transmission Cost Causation Study* for next comprehensive tariff application
  - Application may be filed in about three years time
  - AESO expects to consult with stakeholders on scope and nature of update to study
- Defer changes to deferral account reconciliation processes until changes to rates proposed in tariff application have been reviewed and approved
  - Possibly provide re-reconciliations of prior years as a compliance filing

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## Responses to Directions

§ 9, pp 265-267



- Eight outstanding directions responded to in tariff application
  - Address TFO O&M costs that may be energy related
  - Conduct further analysis on appropriate prepaid O&M rate
  - Propose additional cost causation refinements if warranted
  - Conduct a study of incremental TFO O&M
  - Conduct further analysis on staged contributions
  - File analysis of incremental O&M costs
  - Address updating of investment levels between tariff applications
  - Consider Commission concern about repeated reconciliations of deferral account years
- One remaining direction on balance of KEG costs to be addressed in 2009 deferral account reconciliation

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## Proceeding Schedule



- April 7 Information requests to AESO
- April 28 AESO responses to information requests
- May 12 Intervener evidence
- May 27 Information requests to interveners
- June 10 Intervener responses to information requests
- June 17 Rebuttal evidence
- June 21 Oral hearing (?)
- Decision mid-November
- Effective date at least 90 days later: March 1, 2011
- Further delay if refiling needed

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## Discussion and Questions



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[www.aesoc.ca](http://www.aesoc.ca) ▶ Tariff ▶ Current Applications ▶ 2010 ISO  
Tariff Application

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