This appendix contains the rates, rider, and terms and conditions section which reflect the 2013 tariff update discussed in section 4 of the AESO’s 2014 ISO Tariff Application. Rates, riders, terms and conditions sections, and tariff appendices not included below are not affected by the tariff update and remain in effect as currently approved.

**Rates**
- Rate DTS Demand Transmission Service
- Rate FTS Fort Nelson Demand Transmission Service
- Rate DOS Demand Opportunity Service
- Rate XOS Export Opportunity Service
- Rate XOM Export Opportunity Merchant Service
- Rate PSC Primary Service Credit

**Riders**
- Rider J Wind Forecasting Service Cost Recovery Rider

**Terms and Conditions**
- Section 8 Construction Contributions for Connection Projects
Applicability

1 Rate DTS applies to system access service provided at a point of delivery to:
   (a) the owner of an electric distribution system;
   (b) a person who has entered into an arrangement directly with the ISO for the provision of system access service under subsection 101(2) of the Act;
   (c) the owner of an industrial system that has been designated as such by the Commission; or
   (d) the City of Medicine Hat.

Rate

2 The charge under Rate DTS in a settlement period will be determined in accordance with subsections 3 through 6 below as the sum of the connection charge, the operating reserve charge, the voltage control charge and the other system support services charge.

Connection Charge

3(1) The connection charge equals the sum, over all rows, of the products calculated by multiplying the volume and charge in each row (a) through (i) of the table below.

<table>
<thead>
<tr>
<th>Volume in Settlement Period</th>
<th>Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System Charge</td>
<td></td>
</tr>
<tr>
<td>(a) Coincident metered demand</td>
<td>$5,033.00/MW/month</td>
</tr>
<tr>
<td>(b) Metered energy</td>
<td>$1.68/MWh</td>
</tr>
<tr>
<td>Local System Charge</td>
<td></td>
</tr>
<tr>
<td>(c) Billing capacity</td>
<td>$1,243.00/MW/month</td>
</tr>
<tr>
<td>(d) Metered energy</td>
<td>$0.70/MWh</td>
</tr>
<tr>
<td>Point of Delivery Charge</td>
<td></td>
</tr>
<tr>
<td>(e) Substation fraction</td>
<td>$10,926.00/month</td>
</tr>
<tr>
<td>(f) First (7.5 × substation fraction) MW of billing capacity</td>
<td>$7,401.00/MW/month</td>
</tr>
<tr>
<td>(g) Next (9.5 × substation fraction) MW of billing capacity</td>
<td>$2,732.00/MW/month</td>
</tr>
<tr>
<td>(h) Next (23 × substation fraction) MW of billing capacity</td>
<td>$1,655.00/MW/month</td>
</tr>
<tr>
<td>(i) All remaining MW of billing capacity</td>
<td>$907.00/MW/month</td>
</tr>
</tbody>
</table>
(2) Coincident metered demand is the metered demand at the point of delivery averaged over the 15-minute interval in which the sum of the metered demands for all Rate DTS and Rate FTS market participants is greatest in the settlement period.

Operating Reserve Charge

4(1) The operating reserve charge equals the sum, over all hours in the settlement period, of the amount calculated in each hour as the product of:

(a) metered energy for the Rate DTS market participant in the hour; and

(b) the total cost of operating reserves in the hour divided by the total metered energy for all Rate DTS and Rate FTS market participants in the hour.

(2) If the operating reserve charge is unable to be calculated for a settlement period in accordance with subsection 4(1) above, the operating reserve charge will be estimated as the sum, over all hours in the settlement period, of the amount calculated in each hour as the product of:

(a) metered energy for the Rate DTS market participant in the hour; and

(b) pool price in the hour multiplied by 5.16%.

Voltage Control Charge

5 The voltage control charge equals metered energy in the settlement period multiplied by $0.03/MWh.

Other System Support Services Charge

6 The other system support services charge equals the sum of:

(a) the highest metered demand in the settlement period multiplied by $20.00/MW/month; and

(b) when power factor is less than 90% during the interval of highest metered demand in the settlement period, $400.00/MVA multiplied by the apparent power difference calculated during the interval of highest metered demand in the settlement period as the difference between the metered apparent power and 111% of metered demand.

Terms

7(1) Rate DTS is separately applicable at each point of delivery, except where it is applicable to totaled points of delivery under subsection 5 of section 13 of the ISO tariff.

(2) If Demand Opportunity Service Rate DOS also applies at the point of delivery, in an hour for which a Rate DOS transaction has been approved by the ISO, metered energy under Rate DTS equals

(a) metered energy up to the Rate DTS contract capacity; plus

(b) any additional metered energy determined under subsection 2(2) of Demand Opportunity Service Rate DOS.

(3) Deferral Account Adjustment Rider C applies to system access service provided under this rate.

(4) Balancing Pool Consumer Allocation Rider F applies to system access service provided under this rate.

(5) The terms and conditions of the ISO tariff form part of this rate.
## Revision History

<table>
<thead>
<tr>
<th>Effective</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013-07-17</td>
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</tr>
<tr>
<td>2011-07-01</td>
<td>Revised and reformatted all subsections, as approved in Commission Decision 2011-275 issued on June 24, 2011.</td>
</tr>
</tbody>
</table>
Applicability

1. Rate FTS applies to system access service provided at the point of delivery to BC Hydro at Fort Nelson, British Columbia:

Rate

2. The charge under Rate FTS in a settlement period will be determined in accordance with subsections 3 through 6 below as the sum of the connection charge, the operating reserve charge, the voltage control charge and the other system support services charge.

Connection Charge

3(1). The connection charge equals the sum, over all rows, of the products calculated by multiplying the volume and charge in each row (a) through (d) of the table below.

<table>
<thead>
<tr>
<th>Volume in Settlement Period</th>
<th>Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System Charge</td>
<td></td>
</tr>
<tr>
<td>(a) Coincident metered demand</td>
<td>$5,033.00/MW/month</td>
</tr>
<tr>
<td>(b) Metered energy</td>
<td>$1.68/MWh</td>
</tr>
<tr>
<td>Local System Charge</td>
<td></td>
</tr>
<tr>
<td>(c) Billing capacity</td>
<td>$1,243.00/MW/month</td>
</tr>
<tr>
<td>(d) Metered energy</td>
<td>$0.70/MWh</td>
</tr>
</tbody>
</table>

(2). Coincident metered demand is the metered demand at the point of delivery averaged over the 15-minute interval in which the sum of the metered demands for all Rate DTS and Rate FTS market participants is greatest in the settlement period.

(3). The rate for the local system charge in subsections 3(1)(c) and 3(1)(d) above is equal to the greater of:

(a) the rate for the local system charge in subsections 3(1)(c) and 3(1)(d) of Rate DTS; or

(b) a specific Fort Nelson rate based on the levelized cost of the original ATCO Electric line providing service to Fort Nelson.

Operating Reserve Charge

4(1). The operating reserve charge equals the sum, over all hours in the settlement period, of the amount calculated in each hour as the product of:

(a) metered energy for the Rate FTS market participant in the hour; and

(b) the total cost of operating reserves in the hour divided by the total metered energy for all Rate DTS and Rate FTS market participants in the hour.
(2) If the operating reserve charge is unable to be calculated for a settlement period in accordance with subsection 4(1) above, the operating reserve charge will be estimated as the sum, over all hours in the settlement period, of the amount calculated in each hour as the product of:

(a) metered energy for the Rate FTS market participant in the hour; and

(b) pool price in the hour multiplied by 5.16%.

Voltage Control Charge

5(1) The voltage control charge equals metered energy in the settlement period multiplied by $0.03/MWh.

(2) Prior to completion of phase 1 of the northwest Alberta transmission development as approved in Approvals U2006 205, U2006-275, U2007-348, U2008-318 and others if applicable, the voltage control charge will also include the sum, over all hours in the settlement period in which the ISO issues a dispatch to a fourth generating unit for transmission must-run service in the Rainbow area, of the cost associated with the dispatch issued for that generating unit in an hour multiplied by the ratio in the hour of:

(a) Fort Nelson load in excess of 25 MW; to

(b) the sum of Fort Nelson load in excess of 25 MW and Alberta Rainbow area load (excluding Fort Nelson load) in excess of 105 MW.

(3) After completion of phase 1 of the northwest Alberta transmission development as approved in Approvals U2006 205, U2006-275, U2007-348, U2008-318 and others if applicable, the voltage control charge will also include the sum, over all hours in the settlement period in which Rainbow area load exceeds 145 MW and transmission must-run generation is required in the Rainbow area, of the cost associated with transmission must-run generation in the Rainbow area in an hour multiplied by the ratio in the hour of:

(a) Fort Nelson load in excess of 38.5 MW; to

(b) the sum of Fort Nelson load in excess of 38.5 MW and Alberta Rainbow area load (excluding Fort Nelson load) in excess of 106.5 MW.

Other System Support Services Charge

6 The other system support services charge equals the sum of:

(a) the highest metered demand in the settlement period multiplied by $20.00/MW/month; and

(b) when power factor is less than 90% during the interval of highest metered demand in the settlement period, $400.00/MVA multiplied by the apparent power difference calculated during the interval of highest metered demand in the settlement period as the difference between the metered apparent power and 111% of metered demand.

Terms

7(1) In addition to any obligations under section 9 of the ISO tariff, if BC Hydro terminates the system access service provided under this rate prior to the full payment of the levelized cost of the original ATCO Electric line providing service to Fort Nelson under subsection 3(3)(b) above; the ISO will determine the amount of the remaining unpaid balance of those costs net of any residual value and BC Hydro will pay that amount to the owner of the transmission facilities.
(2) Deferral Account Adjustment Rider C applies to system access service provided under this rate.

(3) The terms and conditions of the ISO tariff form part of this rate.

**Revision History**

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<thead>
<tr>
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</tr>
</thead>
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</tr>
<tr>
<td>2011-07-01</td>
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</tr>
</tbody>
</table>
Applicability
1 Rate DOS applies to system access service provided at a point of delivery to a market participant who:
   (a) receives system access service under Demand Transmission Service Rate DTS;
   (b) is eligible for demand opportunity service under section 12 of the ISO tariff; and
   (c) is recallable in accordance with the provisions of this rate.

Metered Energy
2(1) A Rate DOS charge applies to metered energy received at a point of delivery in every hour:
   (a) for which a Rate DOS transaction has been approved by the ISO;
   (b) above the Rate DTS contract capacity for the system access service; and
   (c) up to the sum of the Rate DTS contract capacity and the approved Rate DOS transaction capacity for the system access service.

   (2) Any metered energy received at a point of delivery in an hour that exceeds the sum of the Rate DTS contract capacity and the approved Rate DOS transaction capacity for the system access service will be added to the market participant’s metered energy received at the point of delivery under Rate DTS in the same settlement period.

Rate
3(1) The charges, recall directive response times and recall priorities for the three types of demand opportunity service are as follows:

<table>
<thead>
<tr>
<th>Rate DOS Type</th>
<th>Rate DOS Charge</th>
<th>Recall Directive Response Time</th>
<th>Recall Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) DOS 7 Minutes</td>
<td>$5.51/MWh</td>
<td>7 minutes</td>
<td>Before Rates DTS, FTS, DOS Term and DOS 1 Hour</td>
</tr>
<tr>
<td>(b) DOS 1 Hour</td>
<td>$10.93/MWh</td>
<td>1 hour</td>
<td>Before Rates DTS, FTS and DOS Term</td>
</tr>
<tr>
<td>(c) DOS Term</td>
<td>$48.43/MWh</td>
<td>7 minutes</td>
<td>Before Rates DTS and FTS</td>
</tr>
</tbody>
</table>

(2) The amount billed for demand opportunity service in a settlement period will be the greater of:
   (a) (i) the Rate DOS charge from subsection 3(1)(a), 3(1)(b), or 3(1)(c) above, as applicable, multiplied by the metered energy during the settlement period; plus
   (ii) an incremental losses charge calculated as the sum, over all transaction hours in the settlement period, of metered energy in the hour multiplied by pool price in the hour multiplied by a loss factor for the facility, where the loss factor is determined in
accordance with ISO rule 9.2 and is available to market participants in the loss factors section of the ISO website; or

(b) a minimum amount equal to the Rate DOS charge from subsection 3(1)(a), 3(1)(b), or 3(1)(c) above, as applicable, multiplied by the approved Rate DOS transaction capacity multiplied by the number of hours in total transactions in the settlement period multiplied by 75%.

(3) A transaction fee of $500.00 will be added to the amount billed for demand opportunity service in a settlement period in which at least one Rate DOS transaction was approved at the point of delivery.

Terms

4(1) Rate DOS is separately applicable at each point of delivery.

(2) If the ISO recalls a market participant’s demand opportunity service, the market participant must curtail load by the amount directed by the ISO which may be an amount up to the approved Rate DOS transaction capacity but which will not require curtailment below the market participant’s Rate DTS contract capacity for the system access service.

(3) In response to a directive from the ISO, a market participant must achieve curtailment of its demand opportunity service load within the response time specified in subsection 3(1)(a), 3(1)(b), or 3(1)(c) above, as applicable.

(4) Losses Calibration Factor Rider E applies to a market participant receiving system access service provided under this rate.

(5) Balancing Pool Consumer Allocation Rider F applies to a market participant receiving system access service provided under this rate, with the exception of the City of Medicine Hat.

(6) The terms and conditions of the ISO tariff form part of this rate.

Revision History

Effective Description

2013-07-17 Updated rate levels applied for as part of 2014 ISO Tariff Application.

2011-07-01 Revised and reformatted all subsections, as approved in Commission Decision 2011-275 issued on June 24, 2011.
Applicability

1 Rate XOS applies to system access service provided to market participants who export electric energy from the interconnected electric system.

Availability

2(1) Export opportunity service is available:

(a) only when sufficient capacity exists on the transmission system to accommodate the capacity scheduled for export; and

(b) a minimum of twenty-four (24) hours following execution of an agreement for system access service for export opportunity service.

(2) Export opportunity service will not be available under Rate XOS 1 Month until after the ISO has implemented an open access same-time information system (OASIS) or similar system.

Rate

3(1) The charges, recall directive response times and recall priorities for the two types of export opportunity service are as follows:

<table>
<thead>
<tr>
<th>Rate XOS Type</th>
<th>Rate XOS Charge</th>
<th>Recall Directive Response Time</th>
<th>Recall Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) XOS 1 Hour</td>
<td>$5.55/MWh</td>
<td>1 hour</td>
<td>Before Rates DTS, FTS, XOS 1 Month and DOS (any type)</td>
</tr>
<tr>
<td>(b) XOS 1 Month</td>
<td>$6.64/MWh</td>
<td>1 hour</td>
<td>Before Rates DTS, FTS and DOS (any type)</td>
</tr>
</tbody>
</table>

(2) The amount billed for export opportunity service in a settlement period will be the greater of:

(a) (i) the Rate XOS charge from subsection 3(1)(a) or 3(1)(b) above, as applicable, multiplied by the market participant’s export interchange transaction during the settlement period; plus

(ii) an incremental losses charge calculated as the sum, over all transaction hours in the settlement period, of the market participant’s export interchange transaction in the hour multiplied by pool price for the hour multiplied by a loss factor for the intertie, where the loss factor is determined in accordance with ISO rule 9.2 and is available to market participants in the loss factors section of the ISO website; or

(b) a minimum amount calculated as the sum, over all transaction hours in the settlement period, of:

(i) the Rate XOS charge from subsection 3(1)(a) or 3(1)(b) above, as applicable, multiplied by the market participant’s hour-ahead scheduled capacity multiplied by 75%; plus

(ii) an incremental losses charge calculated as the market participant’s hour-ahead scheduled capacity multiplied by 75% multiplied by pool price for the hour multiplied by a
loss factor for the intertie, where the loss factor is determined in accordance with ISO rule 9.2 and is available to market participants in the loss factors section of the ISO website.

(3) An operating reserve charge, an other system support services charge or both will be added to the amount billed for export opportunity service in a settlement period when the transaction requires the ISO to procure incremental operating reserves, incremental system support services or both.

(4) A transaction fee of $500.00 will be added to the amount billed for export opportunity service in a settlement period in which at least one Rate XOS transaction was approved for the market participant.

Terms

4(1) Rate XOS is separately applicable at each point of interconnection.

(2) In response to a directive from the ISO, a market participant must achieve curtailment of its export opportunity service within the response time specified in subsection 3(1)(a) or 3(1)(b) above, as applicable.

(3) The minimum and maximum terms for the two types of export opportunity service are as follows:

<table>
<thead>
<tr>
<th>Rate XOS Type</th>
<th>Minimum Term</th>
<th>Maximum Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) XOS 1 Hour</td>
<td>1 hour</td>
<td>1 calendar month</td>
</tr>
<tr>
<td>(b) XOS 1 Month</td>
<td>1 calendar month</td>
<td>1 calendar year</td>
</tr>
</tbody>
</table>

(4) Losses Calibration Factor Rider E applies to market participants receiving system access service provided under this rate.

(5) The terms and conditions of the ISO tariff form part of this rate.

Revision History

Effective Description

2013-07-17 Updated rate levels applied for as part of 2014 ISO Tariff Application.

2011-07-01 Revised and reformatted all subsections, as approved in Commission Decision 2011-275 issued on June 24, 2011.
Applicability

1 Rate XOM applies to system access service provided to market participants who export electric energy from the interconnected electric system utilizing a merchant intertie, defined in accordance with subsection 27(4) of the Transmission Regulation as an intertie for which the cost of planning, designing, constructing, operating and interconnecting is paid by the person who proposed the intertie and other persons that directly benefit from the intertie.

Availability

2(1) Export opportunity merchant service is available:

(a) only when sufficient capacity exists on the transmission system to accommodate the capacity scheduled for export; and

(b) a minimum of twenty-four (24) hours following execution of an agreement for system access service for export opportunity merchant service.

(2) Export opportunity merchant service will not be available under Rate XOM 1 Month until after the ISO has implemented an open access same-time information system (OASIS) or similar system.

Rate

3(1) The charges, recall directive response times and recall priorities for the two types of export opportunity merchant service are as follows:

<table>
<thead>
<tr>
<th>Rate XOM Type</th>
<th>Rate XOM Charge</th>
<th>Recall Directive Response Time</th>
<th>Recall Priority</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) XOM 1 Hour</td>
<td>$5.55/MWh</td>
<td>1 hour</td>
<td>Before Rates DTS, FTS, XOM 1 Month, and DOS (any type)</td>
</tr>
<tr>
<td>(b) XOM 1 Month</td>
<td>$6.64/MWh</td>
<td>1 hour</td>
<td>Before Rates DTS, FTS and DOS (any type)</td>
</tr>
</tbody>
</table>

(2) The amount billed for export opportunity merchant service in a settlement period will be the greater of:

(a) the Rate XOM charge from subsection 3(1)(a) or 3(1)(b) above, as applicable, multiplied by the market participant’s export interchange transaction during the settlement period; or

(b) a minimum amount calculated as the sum, over all transaction hours in the settlement period, of the Rate XOM charge from subsection 3(1)(a) or 3(1)(b) above, as applicable, multiplied by the market participant’s hour-ahead scheduled capacity multiplied by 75%.

(3) An operating reserve charge, an other system support services charge or both will be added to the amount billed for export opportunity merchant service in a settlement period when the transaction requires the ISO to procure incremental operating reserves, incremental system support services or both.
(4) A transaction fee of $500.00 will be added to the amount billed for export opportunity merchant service in a settlement period in which at least one Rate XOM transaction was approved for the market participant.

Terms

4(1) Rate XOM is separately applicable at each point of interconnection.

(2) In response to a directive from the ISO, a market participant must achieve curtailment of its export opportunity merchant service within the response time specified in subsection 3(1)(a) or 3(1)(b) above, as applicable.

(3) The minimum and maximum terms for the two types of export opportunity merchant service are as follows:

<table>
<thead>
<tr>
<th>Rate XOM Type</th>
<th>Minimum Term</th>
<th>Maximum Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) XOM 1 Hour</td>
<td>1 hour</td>
<td>1 calendar month</td>
</tr>
<tr>
<td>(b) XOM 1 Month</td>
<td>1 calendar month</td>
<td>1 calendar year</td>
</tr>
</tbody>
</table>

(4) The terms and conditions of the ISO tariff form part of this rate.

Revision History

Effective Description
2013-07-17 Introduced for export service over Alberta-Montana intertie as part of 2014 ISO Tariff Application.
2011-07-01 Revised and reformatted all subsections, as approved in Commission Decision 2011-275 issued on June 24, 2011.
Applicability

1(1) Rate PSC applies to system access service provided at a point of delivery to a market participant who receives system access service under Demand Transmission Service Rate DTS and:

   (a) has purchased, owns, and operates its own transformation facilities to step transmission voltage down to 25 kV or less, and associated low-voltage facilities; or

   (b) is served through an unconventional connection such as one using metering transformers.

(2) Rate PSC is not available for system access service to an isolated community as defined under the Isolated Generating Units and Customer Choice Regulation.

Rate

2(1) The primary service credit compensates a market participant whose connection does not include conventional transformation facilities owned by a owner of transmission facilities, including a connection for a market participant who has purchased, owns and operates its transformer.

(2) The primary service credit equals the sum of the products calculated by multiplying the volume and credit in each row (a) through (e) of the table below.

<table>
<thead>
<tr>
<th>Volume in Settlement Period</th>
<th>Credit</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a) Substation fraction</td>
<td>$8,632.00/month</td>
</tr>
<tr>
<td>(b) First (7.5 × substation fraction) MW of billing capacity</td>
<td>$5,847.00/MW/month</td>
</tr>
<tr>
<td>(c) Next (9.5 × substation fraction) MW of billing capacity</td>
<td>$2,158.00/MW/month</td>
</tr>
<tr>
<td>(d) Next (23 × substation fraction) MW of billing capacity</td>
<td>$1,307.00/MW/month</td>
</tr>
<tr>
<td>(e) All remaining MW of billing capacity</td>
<td>$907.00/MW/month</td>
</tr>
</tbody>
</table>

Terms

3(1) Rate PSC is separately applicable at each point of delivery, except where it is applicable to totalized points of delivery under subsection 5 of section 13 of the ISO tariff.

(2) The primary service credit is provided in conjunction with a reduced maximum local investment in accordance with subsection 8 of section 8 of the ISO tariff.

(3) The terms and conditions of the ISO tariff form part of this rate.
**Revision History**

<table>
<thead>
<tr>
<th>Effective Date</th>
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<tbody>
<tr>
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</tr>
</tbody>
</table>
Applicability

1(1) Rider J applies to system access service provided under Supply Transmission Service Rate STS for a wind-powered generating unit.

(2) Rider J applies in all settlement periods from July 1, 2011 to December 31, 2013.

Rider

2(1) Rider J recovers the costs paid by the ISO for provision of a wind forecasting service for wind-powered generating units in Alberta.

(2) For each calendar year indicated in column (b) of the table below, the charge under Rider J in a settlement period in that year is the amount provided in column (e) of the table below multiplied by the metered energy produced in the settlement period.

<table>
<thead>
<tr>
<th>(a)</th>
<th>(b)</th>
<th>(c)</th>
<th>(d)</th>
<th>(e)</th>
<th>(f)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basis Year</td>
<td>Cost ($)</td>
<td>Energy (MWh)</td>
<td>Charge ($/MWh)</td>
<td>Revenue ($)</td>
<td></td>
</tr>
<tr>
<td>Actual 2010</td>
<td>$300,318</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td>Actual 2011</td>
<td>$338,400</td>
<td>1,161,500</td>
<td>$0.13/MWh</td>
<td>$150,955</td>
<td></td>
</tr>
<tr>
<td>Actual 2012</td>
<td>$338,400</td>
<td>2,574,000</td>
<td>$0.14/MWh</td>
<td>$360,360</td>
<td></td>
</tr>
<tr>
<td>Forecast 2013</td>
<td>$338,400</td>
<td>2,574,000</td>
<td>$0.15/MWh</td>
<td>$386,100</td>
<td></td>
</tr>
<tr>
<td>Forecast 2014</td>
<td>$324,560</td>
<td>3,175,000</td>
<td>$0.16/MWh</td>
<td>$508,000</td>
<td></td>
</tr>
<tr>
<td>Forecast Total</td>
<td>$1,640,078</td>
<td>6,484,500</td>
<td>—</td>
<td>$1,405,455</td>
<td></td>
</tr>
</tbody>
</table>

(3) The charge in column (e) of the table in subsection 2(2) above is based on forecast values of cost, energy and revenue as provided in columns (c), (d) and (f) of that table, and is forecast to escalate by 10% each calendar year.

(4) At the end of each calendar year, the ISO will adjust the charge for the remaining calendar years to reflect variances from the forecasts of cost and energy in columns (c) and (d) of the table in subsection 2(2) above, and will incorporate the adjustments in the table in the ISO tariff for the following calendar year.

Terms

3(1) Rider J is separately applicable at each point of supply.

(2) The terms and conditions of the ISO tariff form part of this rider.
**Revision History**

<table>
<thead>
<tr>
<th>Effective</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013-07-17</td>
<td>Updated table in subsection 2(2) as part of 2014 ISO Tariff Application.</td>
</tr>
</tbody>
</table>
Applicability

1. This section applies to a market participant who has requested or is receiving system access service under:

   (a) Demand Transmission Service Rate DTS;
   (b) Primary Service Credit Rate PSC; or
   (c) Supply Transmission Service Rate STS.

Connection Costs

2. The costs of a connection project for a market participant will be those costs reasonably associated with facilities that:

   (a) an owner of a transmission facility will own and operate;
   (b) are required to:
      (i) provide system access service to a new point of delivery or point of supply; or
      (ii) increase the capacity of or improve system access service to an existing point of delivery or point of supply; and
   (c) are reasonably required to meet the market participant’s:
      (i) demand and supply forecast; and
      (ii) reliability and operating requirements.

Classification of Participant-Related and System-Related Costs

3(1) All costs of a connection project will be classified as either participant-related or system-related.

(2) Participant-related costs will be those costs related to a contiguous connection project including costs associated with:

   (a) the connection substation for the point of delivery or point of supply, including in out line configurations, where required;
   (b) new radial transmission lines, including double-radial configurations, with only one (1) transmission source from the transmission system to the connection substation;
   (c) a share of existing transmission facilities that were constructed to connect another market participant, where the existing facilities originally began commercial operation within the past twenty (20) years and where the share is determined in accordance with subsection 3 of section 9 of the ISO tariff;
   (d) line moves or burials of existing transmission line;
   (e) communication at the point of delivery or point of supply;
   (f) communication enhancements required at the nearest substation with communications equipment to allow direct communication between it and the connection substation;
(g) breakers and associated equipment required for the connection of the new radial transmission line to an existing substation;

(h) salvage labour required to remove existing transmission facilities to allow the installation of new or replacement facilities for a connection project, except where the cost of the removed facilities is treated as a capital maintenance cost by the owner of the transmission facility;

(i) changes to protection systems, equipment or settings related to the addition of a generating unit on an electric distribution system served through the connection substation;

(j) a remedial action scheme, if required;

(k) a phasor measurement unit, if required;

(l) the advancement of transmission facilities included as part of a critical transmission development or regional transmission system project under subsection 3(3)(b) below, calculated as the difference between the present values of the capital costs of the advanced and the as-planned facilities using the discount rate provided in subsection 11 below;

(m) facilities previously classified as system-related under subsection 3(3)(c) below and now reclassified as participant-related to meet the requirements of the connection project; and

(n) other facilities required to complete the market participant’s connection, including transmission facilities required to enable the market participant to meet all relevant technical requirements for the connection project.

(3) System-related costs will be those costs related to a connection project including non contiguous components of the project and any costs associated with:

(a) looped transmission facilities, which are facilities that increase the number of electrical paths between any two (2) substations, excluding the substation serving the market participant and which exclude any new radial transmission line;

(b) radial transmission facilities which, within five (5) years of commercial operation, are planned to become looped as part of a critical transmission development or regional transmission system project:
   (i) in the ISO’s most recent long-term transmission system plan;
   (ii) in a needs identification document filed with the Commission; or
   (iii) as the ISO reasonably expects will be required in the future; and

(c) transmission facilities in excess of the minimum size required to serve the market participant where, in the opinion of the ISO, economics or system planning support the development of such facilities.

Facilities in Excess of Good Electric Industry Practice

4 A market participant must pay, as part of the construction contribution, any participant-related costs of facilities which are deemed, in the opinion of the ISO, to be in excess of those required by good electric industry practice.
Valuation of Facilities for Contribution Determination

5(1) When calculating costs, equipment used for a connection project will generally be valued at the replacement cost new which is the current cost of similar new equipment having the nearest equivalent capability to the equipment being valued.

(2) Where a connection project involves the installation of a transformer that replaces a smaller transformer which was removed from service at a substation, the participant-related costs for the connection project:

(a) will be reduced by the replacement cost new of the removed transformer when the owner of the transmission facility either:
   (i) deems the transformer which is removed to be re-deployable for use at another substation or suitable for use as an operating spare; or
   (ii) treats the cost of the transformer which is removed as a capital maintenance cost; or

(b) subject to subsection 5(2)(a) above, will not be reduced in any other circumstances including when the owner of the transmission facility scraps the transformer which is removed without treating its cost as a capital maintenance cost.

Allocation of Costs to Market Participants

6(1) The balance of participant-related costs remaining after:

(a) the exclusion of costs, if any, under subsection 4 above reflecting facilities in excess of those required by good electric industry practice; and

(b) the reduction of costs, if any, under subsection 5 above reflecting replacement of a transformer removed from service;

will be allocated to the market participant at the substation at which system access service is provided.

(2) Where facilities are used to provide system access services, which may be solely under Rate DTS, solely under Rate STS or under a combination of both, to more than one market participant at a single substation, the balance of participant-related costs identified in subsection 6(1) will be allocated among those market participants.

(3) The balance of participant-related costs referred to in subsections 6(1) and 6(2) above will be allocated to each market participant by multiplying those costs by the average substation fraction for the market participant determined in accordance with subsection 3(3) of section 9 of the ISO tariff.

(4) Costs allocated to a market participant taking service under Rate DTS are deemed to be demand-related costs.

(5) Costs allocated to a market participant taking service under Rate STS are deemed to be supply-related costs.

Determination of Construction Contribution

7(1) The construction contribution will be calculated in accordance with the construction contribution provisions of the ISO tariff in effect on the date on which the Commission issues permit and licence for the connection project.
(2) A market participant must pay construction contribution amounts to the owner of the transmission facility in accordance with the financial obligation provisions of section 5 of the ISO tariff.

(3) For a market participant receiving service under Rate DTS, the construction contribution is calculated as the demand-related costs less the local investment determined under subsection 8 below.

(4) For a market participant receiving service under Rate STS, the construction contribution is equal to the supply-related costs.

(5) In addition, a market participant receiving service under Rate STS must pay the ISO any owner’s contribution for a generating unit required under section 10 of the ISO tariff.

**Determination of Local Investment**

8(1) For a market participant taking service under Rate DTS, or under Rate DTS with Rate PSC, the maximum local investment will be based on the contract capacity and investment term set out in the system access service agreement for the connection project.

(2) The contract capacity used for the local investment calculation must not include any contract capacity transferred from another point of delivery.

(3) The investment term must be from five (5) to twenty (20) years inclusive, commencing on the date of commercial operation.

(4) For a connection project for a new point of delivery, the maximum local investment amount will be the sum of the annual amounts calculated for each year in the investment term by adding the products of the values from each of rows (c) through (g) of the table below, where the product for a row is calculated by multiplying:

(a) the substation fraction or contract capacity, as applicable, from column A; and

(b) the investment amounts from column B or column C, as applicable.

<table>
<thead>
<tr>
<th>Column A</th>
<th>Column B</th>
<th>Column C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier</td>
<td>Investment for Service Under Rate DTS</td>
<td>Investment for Service Under Rate DTS with Rate PSC</td>
</tr>
<tr>
<td>(c) Substation fraction (for new points of delivery only)</td>
<td>$52 000/year</td>
<td>$10 920/year</td>
</tr>
<tr>
<td>(d) First (7.5 × substation fraction) MW of contract capacity</td>
<td>$35 350/MW/year</td>
<td>$7 425/MW/year</td>
</tr>
<tr>
<td>(e) Next (9.5 × substation fraction) MW of contract capacity</td>
<td>$13 050/MW/year</td>
<td>$2 740/MW/year</td>
</tr>
<tr>
<td>(f) Next (23 × substation fraction) MW of contract capacity</td>
<td>$7 900/MW/year</td>
<td>$1 660/MW/year</td>
</tr>
<tr>
<td>(g) All remaining MW of contract capacity</td>
<td>$4 250/MW/year</td>
<td>$0/MW/year</td>
</tr>
</tbody>
</table>
(5) For a connection project at an existing point of delivery to accommodate a contract capacity increase:

   (a) the contract capacity used for the local investment calculation will be the incremental contract capacity since the most recent change in construction contribution at the point of delivery;

   (b) the substation fraction will be calculated based on contract capacities after the increase;

   (c) the existing contract capacity establishes the tier in which investment will become available for the incremental contract capacity; and

   (d) where the sum of existing and incremental contract capacities exceeds the remaining MW in the tier, investment will become available from subsequent tiers, as appropriate.

(6) If a market participant includes increases or decreases to contract capacity over the investment term for a connection project, the local investment will be the sum of the investment for each incremental amount of contract capacity, which will be:

   (a) calculated in accordance with subsections 8(4) and 8(5) above, based on each increment of contract capacity and the years for which each increment is contracted, and

   (b) discounted from the beginning of the first month in which the increment of contract capacity exists back to the date of commercial operation of the connection project, using the discount rate provided in subsection 11 below.

(7) The maximum local investment calculated in subsection 8(4), 8(5), or 8(6) above will not exceed the demand-related costs.

Operations and Maintenance

9(1) A market participant taking service under Rate DTS must pay, as part of the construction contribution, an operations and maintenance charge that will be added to any participant-related costs of facilities which are deemed to be in excess of those required by good electric industry practice in subsection 4 above.

(2) The operations and maintenance charge will be estimated by the market participant and agreed to by the ISO:

   (a) as the present value of the full incremental maintenance cost, incremental operations cost, and overheads associated with the operations and maintenance of the facilities which are deemed to be in excess of those required by good electric industry practice,

   (b) over the useful life of those facilities or twenty (20) years, whichever is less.

(3) The discount rate used in the present value calculation will be that provided in subsection 11 below.

Limitations

10 The ISO will have discretion in the application of the construction contribution provisions in the ISO tariff, including the determination of costs to be system-related in certain circumstances that might, under strict application of the construction contribution provisions, have been classified as participant-related.
Discount Rate

11(1) The discount rate applicable to the calculation of construction contributions under this section 8 of the ISO tariff and payments in lieu of notice under section 9 of the ISO tariff will be determined as:

\[
\text{discount rate} = \left( (1 - E) \times (YLD + 1\%) \right) + \left( \frac{E \times \text{ROE}}{1 - T} \right)
\]

where:

(a) \( E \) is equal to the Commission-approved equity ratio applicable to the owner of transmission facilities, as amended from time to time;

(b) \( YLD \) is equal to the yield on 30-year Government of Canada bonds;

(c) \( \text{ROE} \) is equal to the Commission-approved rate of return on equity applicable to the owner of the transmission facilities, as amended from time to time; and

(d) \( T \) is equal to the combined federal and provincial income tax rate applicable to the owner of the transmission facilities.

(2) Where an owner of transmission facilities does not pay income tax, including a non-income tax paying municipal owner of transmission facilities, the tax rate \( T \) used in subsection 11(1) above will be equal to zero (0).

Miscellaneous

12(1) Where transmission facilities must be relocated, the ISO will make reasonable efforts to ensure that the party causing the relocation pays all reasonable costs associated with the relocation.

(2) Where new facilities between adjacent balancing authority areas are required, the cost of such facilities will be shared between the ISO and the party responsible for costs in the other balancing authority area based on the extent to which each benefits directly from the facilities.

Revision History

Effective Description
2013-07-17 Updated maximum investment levels applied for as part of 2014 ISO Tariff Application.
2011-07-01 Revised and reformatted all subsections, as approved in Commission Decision 2011-275 issued on June 24, 2011.