Section 501.10 Transmission Loss Factor Methodology and Requirements

Applicability

1 Section 501.10 applies to:

(a) a **market participant**:

(i) making a request to the **ISO** to determine a **loss factor** with respect to a **generating unit** or **aggregated generating facility** the **market participant** proposes to construct; or

(ii) receiving service under Rate IOS or Rate XOS of the **ISO tariff**; and

(b) the **ISO**.

Requirements

Establish and Maintain Loss Factors

2(1) The **ISO** must establish and maintain for each calendar year **loss factors** for:

(a) generation facilities, being a **generating unit**, an **aggregated generating facility**, an industrial system that has been designated as such by the **Commission**, Fort Nelson and the City of Medicine Hat;

(b) service under Rate XOS of the **ISO tariff**;

(c) service under Rate IOS of the **ISO tariff**; and

(d) service under Rate DOS of the **ISO tariff**;

in accordance with this section of the **ISO rules**.

(2) Notwithstanding subsection 2(1), if the **ISO** determines that a modification, an enhancement or an expansion to the **transmission system** affects:

(a) the **loss factors** of a generation facility by greater than or equal to a change of zero point two five (0.25) percent, then the **ISO** may adjust the **loss factors** for the generation facility; or

(b) the average losses of the **transmission system** by greater than or equal to a change of five (5) percent then the **ISO** may adjust the **loss factors** for the entire **transmission system**.

(3) The **ISO** must make **loss factors** publicly available by posting them on the AESO website.

(4) The **ISO** must post the **loss factors** by the first week in November of each year prior to them becoming effective and must include:

(a) the effective date of the **loss factors** and the period of time they are in force pursuant to subsection 2(1); and

(b) the **generic stacking order** for each year.

(5) The **ISO** must post, by March 31 of each year, a list of forecasted non-binding **loss factor** ranges for the fifth (5^{th}) year subsequent to the year referenced in 2(4)(a) for all **generating units** and other services expected to be directly connected to the **transmission system** by the fifth (5^{th}) year.

(6) Notwithstanding subsection 2(5), the **ISO** must, if it has filed an update to the 10-year plan referenced in the *Transmission Regulation* within the ninety (90) **days** prior to March 31, post the list of forecasted non-binding **loss factor** ranges referenced in subsection 2(5) within ninety (90) **days** from the date of filing the update.

(7) A **market participant** must make any request pursuant to subsection 32(1) of the *Transmission Regulation* by completing and submitting a *Preliminary Loss Factor Calculation Application* available on the AESO website and paying the fee specified on the foregoing application.

(8) The **ISO** may, prior to completing a preliminary **loss factor** calculation, require the **market participant** to provide further information in the form of a connection proposal.

Recovery of Costs of Losses on the Transmission System

3(1) The **ISO** must calculate an import **loss factor** for a **market participant** receiving **system access service** for merchant transmission lines connected to the **transmission system** at its connection point to the **interconnected electric system** but will not include losses resulting from the average flow of imports and exports on the merchant transmission line in the calculation.

(2) The **ISO** must apply the **calibration factor** to all **loss factors** for the recovery of **transmission system** losses and to the average losses calculated on the import and export transfer paths.

Loss Factor Modeling and Assumption Details

4 The **ISO** must follow the **loss factor** methodology set out in Appendix 1.

Appendices

Appendix 1 – *Transmission Loss Factor Methodology*

Revision History

Effective	Description
2012-10-10	Initial Release

Appendix 1

Transmission Loss Factor Methodology

Methodolgy

Load Flow Loss Factors

1(1) The **ISO** must calculate raw **loss factors** for each of twelve (12) base case load flow conditions which are each selected to represent a typical operating condition on the **transmission system**, based on forecasted system loading conditions, historical **intertie** load flows and historical outputs of existing generation facilities.

(2) The **ISO** must ensure the twelve (12) base cases used to determine the load flows for the **transmission system** are:

(a) used to give weighted average values of **transmission system** loading conditions and losses;

(b) represented over each of the four (4) “three-month seasons” of the year (winter, spring, summer and fall); and

(c) based on weighted average values taken at representative high, medium and low load conditions for each season.

(3) The **ISO** must model each generation facility in the twelve (12) base cases using the following criteria:

(a) historical hourly settlement data from June 1 of Y-2 to May 30 of Y-1, where Y is the forthcoming year, for existing generation facilities, service under Rate DOS, Rate XOS and Rate IOS of the **ISO tariff** only; and

(b) new generation facilities that have applied to be connected to the **transmission system** and which are forecasted to be connected in the following year, using the production profile the **legal owner** provides prior to May 31 preceding the **loss factor** year; or

(c) in the absence of the production profile in subsection 1(3)(b), the production profile the **ISO** determines, based on its analysis of the **generating unit**’s technology, using incapability factor (ICbF) levels obtained from the five (5) year averages published in the latest *Canadian Electricity Association Generation Equipment Status Annual Report* and **supply transmission service** levels for the capacity calculations.

(4) The **ISO** must, in the methodology to determine a load flow based raw **loss factor**, known as the “Corrected R Matrix 50% Area Load Adjustment Methodology”, calculate raw **loss factors** analytically with a custom program that:

(a) uses the load flow solution as a base; and

(b) computes the raw **loss factors** analytically;

using a single numerical process.

(5) The **ISO** must, in the methodology to determine a load flow based raw **loss factor**, apply the following assumptions:

(a) the generation facility or service under the **ISO tariff** rate for which the **loss factor** is to be evaluated is going to supply the next increment in load on the **transmission system**;

(b) the generation facility or service under the **ISO tariff** rate for which the **loss factor** is to be calculated becomes the swing bus for the **transmission system**;

(c) every load within the **transmission system** would be increased by a common factor and a loss gradient would be determined equal to the total change in **transmission system** losses divided by the change in output of the generation facility or service under the **ISO tariff** rate for which the **loss factor** is being calculated; and

(d) the raw **loss factor** is set equal to one half (1/2) of the gradient.

(6) The **ISO** must, when implementing the methodology to determine a load flow based raw **loss factor**, assume:

(a) all bus voltages are set according to the historical voltage levels on these buses;

(b) the VAr component of the load is changed as a result of the change in MW load, to maintain the ratio between them unchanged;

(c) the load change is applicable to only loads in the **transmission system**;

(d) for industrial complexes where the industrial complex is receiving power, the increment in load is based on the net load at the metering point; and

(e) for industrial complexes where the industrial complex is supplying power, the industrial complex is treated as an equivalent **generating unit** with output equal to net-to-grid at the metering point.

(7) The **ISO** must, when calculating adjusted load flow raw **loss factors**:

(a) attempt to account for almost one hundred (100) percent of the load flow losses for the **transmission system** when the load flow raw **loss factors** are multiplied by the output in MW of all **loss factor** customers and summed for all generation in Alberta;

(b) not include small power research and development **generating units**; and

(c) include a small load flow seasonal shift **loss factor** compensating for the over-assigned or unassigned losses, including the unassigned component of the small power research and development **generating units** with distribution based on their power output in the load flow.

Energy Loss Factors

2 The **ISO** must calculate energy–based normalized **loss factors** as follows:

(a) calculate a seasonal adjusted raw **loss factor** equal to the weighted average of the three (3) adjusted raw **loss factors** determined for each of the three (3) system loading conditions for the season;

(b) multiply the seasonal adjusted raw **loss factor** by the forecast generation facility and service under Rate XOS, Rate IOS and Rate DOS volumes to establish a preliminary allocation of losses for each season;

(c) compare the total allocation to the estimated energy losses for the system and introduce a seasonal shift factor to account for any differences between allocated and estimated energy losses; and

(d) calculate the normalized annual **loss factor** as the weighted average of the four (4) seasonal shifted **loss factors**.

Compressed Loss Factors

3(1) The **ISO** must, if a situation arises where compression is necessary, adopt the following methodology:

(a) limit the **loss factors** to a compressed range of plus or minus twelve (12%) percent by clipping, and

(b) apply a compression shift factor to the **loss factors** not on the **loss factor** limit, with the first calculation being intended to balance the energy loss.

(2) The **ISO** must, if any **loss factors** lie outside the range set out in subsection 3(1)(a) as a result of the application of the compression shift factor:

(a) linearly compress the **loss factors** that were not originally on the **loss factor** compression limits; and

(b) multiply the difference between the seasonally shifted **loss factor** and the system average **loss factor** by a constant factor and add the result to the average **loss factor** to ensure that all **loss factors** are within the limit set out in subsection 3(1)(a);

and the final **loss factor** is referred to as a 'compressed' **loss factor**.

A MathCAD implementation of the clipping algorithm is shown on the next page.

MathCAD Implementation of Clipping with Linear Compression Algorithm ('Adjusted by a Common Method') Clipping Plus Linear Compression Plus Seasonal Shift Factor

$$
Lf_4(Lf, E, k_{max}, k_{min}) := \left|
\begin{array}{l}
Losses \leftarrow ((Lf))^T \cdot E \\
Lf_{av} \leftarrow \dfrac{Losses}{Sum(E)} \\
Lf_{max} \leftarrow k_{max} \cdot Lf_{av} \\
Lf_{min} \leftarrow k_{min} \cdot Lf_{av} \\
lf \leftarrow \left|
\begin{array}{l}
j \leftarrow -1 \\
\text{for } i \in 0..(rows(Lf) - 1) \\
\quad \left|
\begin{array}{l}
lf_i \leftarrow Lf_{max} \ \text{ if } \ Lf_i > Lf_{max} \\
lf_i \leftarrow Lf_{min} \ \text{ if } \ Lf_i < Lf_{min} \\
\text{if } \left(Lf_i \geq Lf_{min}\right) \wedge \left(Lf_i \leq Lf_{max}\right) \\
\quad \left|
\begin{array}{l}
lf_i \leftarrow Lf_i \\
j \leftarrow j + 1 \\
iref_j \leftarrow i \\
lftemp_j \leftarrow Lf_i \\
Etemp_j \leftarrow E_i
\end{array}
\right.
\end{array}
\right. \\
lf
\end{array}
\right. \\
sf \leftarrow \dfrac{Losses - lf^T \cdot E}{Sum(Etemp)} \ \text{ if } \ j > 0 \\
lftemp \leftarrow lftemp + sf \\
lftemp2 \leftarrow Lf_1(lftemp, Etemp, k_{max}, k_{min}) \\
\text{for } k \in 0..j \qquad \text{if } \ j \geq 0 \\
\quad lf_{(iref_k)} \leftarrow lftemp2_k \\
lf
\end{array}
\right.
$$

Lf is a vector of uncompressed but normalized loss factors.
E is a corresponding vector of generator energy volumes.
k_{max} is a scalar that when multiplied by the average loss factor defines the maximum permitted loss factor
k_{min} is a scalar that when multiplied by the average loss factor defines the minimum permitted loss factor
Lf_1 is the linear compression algorithm

Linear Compression

$$
Lf_1(Lf, E, k_{max}, k_{min}) := \left|
\begin{array}{l}
Losses \leftarrow Lf^T \cdot E \\
Lf_{av} \leftarrow \dfrac{Losses}{Sum(E)} \\
Lf_{max} \leftarrow k_{max} \cdot Lf_{av} \\
Lf_{min} \leftarrow k_{min} \cdot Lf_{av} \\
K_s \leftarrow \max\left(\min\left(\dfrac{Lf_{max} - Lf_{av}}{\max(Lf) - Lf_{av}}, \dfrac{Lf_{min} - Lf_{av}}{\min(Lf) - Lf_{av}}, 1\right), 0\right) \\
\text{for } i \in 0..\, rows(Lf) - 1 \\
\quad Lf_{1_i} \leftarrow Lf_{av} + (Lf_i - Lf_{av}) \cdot K_s \\
Lf_1
\end{array}
\right.
$$

Lf is a vector of uncompressed but normalized loss factors.
E is a corresponding vector of generator energy volumes.
k_{max} is a scalar that when multiplied by the average loss factor defines the maximum permitted loss factor
k_{min} is a scalar that when multiplied by the average loss factor defines the minimum permitted loss factor

Loss Factor Procedures

Development of Base Cases

4(1) The **ISO** must apply a single suite of up-to-date base cases for calculating the annual **loss factors** from January through December and the load profiles contained in the base cases must include:

(a) high, medium, and low load cases for the three (3) **month** period December, January and February, being the winter season;

(b) high, medium, and low load cases for the three (3) **month** period March, April and May, being the spring season;

(c) high, medium, and low load cases for the three (3) **month** period June, July and August, being the summer season; and

(d) high, medium, and low load cases for the three (3) **month** period September, October and November, being the fall season.

(2) The **ISO** must obtain the intermediate values for load duration as shown in the following Figure 1:

Figure 1: Graphical representation of duration curve and intermediate values

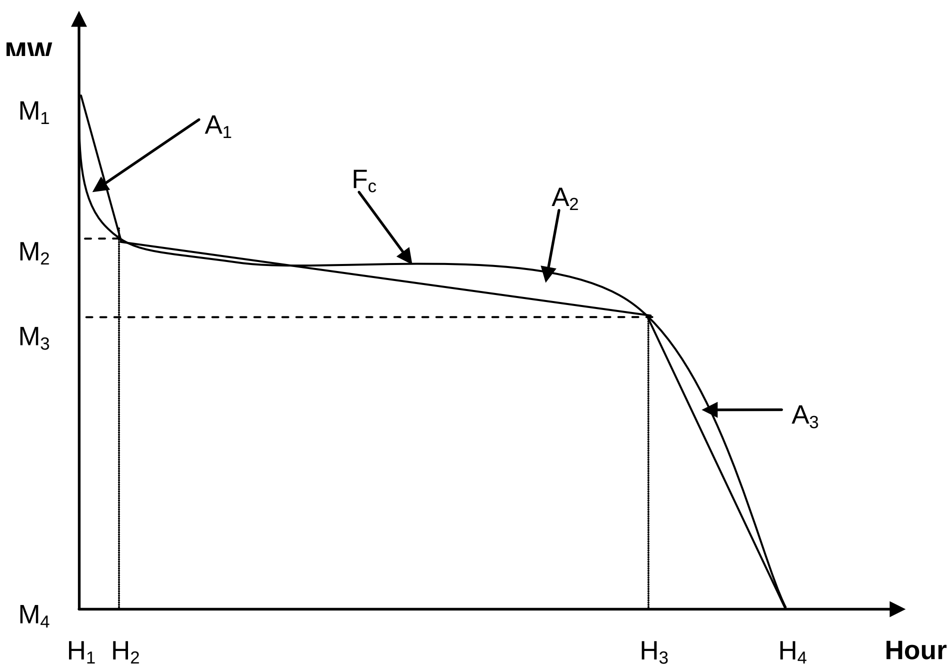

Figure 1 shows the graphic representation used in determination of the three (3) segments.
Hours are plotted in the x-axis while MWs are plotted in the y-axis from maximum to minimum.
The duration curve is named F_c.
Three (3) straight lines form the three (3) segments and these three (3) straight lines are a linear representation of the curve.
The first and last data of F_c is known and they are H_1 and H_4 for Hours and M_1 and M_4 for MWs.

(3) The **ISO** must determine the intermediate hours, H_2 and H_3 and MWs, M_2 and M_3 as follows:

(a) obtain the area under the straight line and duration curve F_c for each segment;

(b) find the difference between these two (2) areas (A_x);

(c) find all three (3) A_xs and add their squares ($A_1^2 + A_2^2 + A_3^2$);

(d) find H_2 and H_3 so that the sum of the squares of A_xs becomes minimum ,i.e. Minimize ($A_1^2 + A_2^2 + A_3^2$);

(e) represent the weight for that segment with the duration of each segment;

(f) use the average MW value for the segment as the average MW value of the corresponding load case;

(g) use $(H_2 – H_1)$ as the duration for the high load case for each season and the following MW

$$M_H = \frac{\sum_{i=1}^{2} MW_i}{H_2 - H_1};$$

(h) use $(H_3 – H_2)$ as the duration for the medium load case for each season and the following MW:

$$M_M = \frac{\sum_{i=2}^{3} MW_i}{H_3 - H_2}; \text{ and}$$

(i) use $(H_4 – H_3)$ as the duration for the low load case for each season and the following MW:

$$M_L = \frac{\sum_{i=3}^{4} MW_i}{H_4 - H_3}.$$

(4) The **ISO** must include the following in the twelve (12) load flow base cases for the forthcoming year:

(a) all facilities that are commissioned as of December 1 of the current year and that have no **Commission** approved plan for decommissioning prior to October 15 of the following year;

(b) any facility the **ISO** selects to be included in all base cases for a season unless the facility has a planned in-service date after the midpoint of the season, in which case, the **ISO** must include the facility in the following season;

(c) any customer-initiated project with an accepted *Connection Proposal* the **ISO** selects to be included in all base cases for a season unless the project has a planned in-service-date after the midpoint of the season, in which case, the **ISO** must include the project in the following season;

(d) any **ISO-**initiated project with an approved **needs identification document** the **ISO** selects to be included in all base cases for a season unless the project has a planned in-service date after the mid-point of the season, in which case, the **ISO** must include them in the following season; and

(e) the three (3) base cases for each season which must have identical physical topology and show all projects whose in-service-date falls on or before the midpoint of the season.

(5) The **ISO** must, for the forthcoming year, adjust the status of facilities to be in-service or out-of-service as follows:

(a) normally in-service status shown on the operating single line diagram; and

(b) seasonally switched device status must show their normally in-service status, unless the **legal owner** of the **transmission facility** explicitly specifies otherwise.

(6) The **ISO** must, for the forthcoming year, use load flows that use bus 1520, being the **WECC** equivalent bus, as the swing bus.

(7) In determining the twelve (12) load flow base cases for the forthcoming year, the **ISO** must use as its load forecast the latest approved forecast the **ISO** created during the current year and must use the same forecast to provide a set of forecast **loss factors** for the fifth (5^{th}) year subsequent to the year referenced in subsection 4(4).

(8) The **ISO** must include the following in the twelve (12) load flow base cases for the fifth (5^{th}) year subsequent to the year referenced in subsection 4(4):

(a) all facilities that are commissioned as of December 1 of the current year and that have no **Commission** approved plan for decommissioning prior to October 15 of the fifth (5^{th}) year out;

(b) any non-wind facility the **ISO** selects to be included in all twelve (12) base cases with a planned in-service date on or before October 15^{th} of the fifth (5^{th}) year;

(c) any wind **aggregated generating facility** the **ISO** selects to be included in all twelve (12) base cases until a forecasted capacity amount of wind generation is reached;

(d) any customer-initiated project the **ISO** selects to be included in all twelve (12) base cases with a planned in-service-date on or before October 15^{th} of the fifth (5^{th}) year;

(e) any **ISO**-initiated project the **ISO** selects to be included in all twelve (12) base cases with a planned in-service date on or before October 15^{th} of the fifth (5^{th}) year; and

(f) the twelve (12) base cases which must have identical physical topology and show all projects whose in-service-date falls on or before October 15 of the fifth (5^{th}) year.

(9) The **ISO** must, for the fifth (5^{th}) year subsequent to the year referenced in subsection 4(4), adjust the status of facilities to be in-service or out-of-service as follows:

(a) normally in-service status shown on the operating single line diagram; and

(b) seasonally switched device status must show their normally in-service status unless the **legal owner** of the **transmission facility** explicitly specifies otherwise.

(10) The **ISO** must, for the fifth (5^{th}) year subsequent to the year referenced in subsection 4(4), use load flows that use bus 1520, being the **WECC** equivalent bus, as the swing bus.

(11) In determining the twelve (12) load flow base cases for the fifth (5^{th}) year subsequent to the year referenced in subsection 4(4), the **ISO** must use as its load forecast the latest approved forecast the **ISO** created during the current year.

Development of Generic Stacking Order

5 The **ISO** must develop a **generic stacking order** each year and must base the **generic stacking order** on at least the following considerations:

(a) **generic stacking order** constructed according to historical **point of supply** metering records for existing generation facilities;

(b) determination of the four (4) load points (H1, H2, H3, and H4) for the generation facilities' duration curves are selected by using the corresponding hour from the load duration curve for each of the seasons;

(c) the **ISO** must determine the MWs under the duration curve for points H1 to H2, H2 to H3, and H3 to H4 by using the following formulas:

$$M_H = \frac{\sum_{i=1}^{2} MW_i}{H_2 - H_1} \; ; \; M_M = \frac{\sum_{i=2}^{3} MW_i}{H_3 - H_2} \; ; \; M_L = \frac{\sum_{i=3}^{4} MW_i}{H_4 - H_3}$$

(d) the **ISO** must use the average value of the total MWs under each section of the duration curve as the output value for corresponding load case in the associated season;

(e) when a shortfall of generation capacity versus system load exists in a base case, the **ISO** must scale down the system load to match supply and if necessary, load adjust all twelve (12) base cases;

(f) the **ISO** must observe the ranking order for generation facilities, based on the historical generation facility response and **loss factor**;

(g) for new generation facilities that have applied to be connected to the **transmission system** and which are forecasted to be connected in the following year, for application using the production profile the **legal owner** provides prior to May 31 preceding the **loss factor** year, or in the absence of that production profile, the production profile the **ISO** determines based on its analysis of the **generating unit**'s technology, using incapability factor (ICbF) levels obtained from the five (5) year averages published in the latest *Canadian Electricity Association Generation Equipment Status Annual Report* and **supply transmission service** levels for the capacity calculations;

(h) add new generation facilities in the **generic stacking order** according to their technology at the end of their representative group; and

(i) the **ISO** must determine the **intertie** values in the same manner as for generation facilities.

Calculation of Loss Factors

6(1) The **ISO** must calculate the **loss factors** for each year using the base cases developed for **firm load**.

(2) The base cases must contain demand opportunity services and be net of service under Rate XOS and Rate IOS of the **ISO tariff** for each **intertie**.

(3) For calculation of **loss factors** for **firm load**, the **ISO** must adjust the resulting issuance of **dispatches** for generation according to the **generic stacking order** to achieve the forecasted net MW exchange at all **interties**.

Calculation of Loss Factors for Firm Load

7(1) The **ISO** must, in developing the twelve (12) base cases for **loss factors** for **firm load**:

(a) use only historical production data to determine the power level to be used for existing generation facilities and service under the **ISO tariff** rates;

(b) include in each base case the magnitude of **dispatches** based on a common annual **generic stacking order**; and

(c) keep the **generic stacking order** the same in each base case with respect to the generation **dispatch** order, but vary the magnitude of energy included in **dispatches** for the generation facilities that are subject to seasonal variation.

(2) The **ISO**, through discussions with the **legal owner** of a new **generating unit**, must:

(a) add new generation facilities to the existing **generic stacking order**;

(b) base the magnitude of a generation facility's **dispatch** on the generation facility's production profile or the **supply transmission service** contract level; and

(c) establish the same **loss factor** as existing generation facilities if the new generation facility is an addition to an existing plant using the same connection configuration.

(3) The base cases used to calculate the **loss factors** for generation facilities and service under the **ISO tariff** rates must all contain a historical net flow for the exchange across the **interties**.

(4) The **ISO** must set the transmission line losses across the **transfer paths** to zero (0) for the purpose of calculating **loss factors** for a generation facility and service under the **ISO tariff** rates and must review the base cases with the **legal owner** to ensure that the historical data used is accurate.

Calculation of Loss Factors for Service Under Rate IOS

8 The **ISO** must, when calculating **loss factors** for service under Rate IOS of the **ISO tariff**, apply the following conditions:

(a) calculate the **loss factors** in the same manner as for generation facilities;

(b) for the Alberta - B.C. **intertie**, calculate the **loss factor** at the buses that the **ISO** identifies, using historical import data and representing the service under Rate IOS as a **generating unit**, and after calculating the **loss factors** for each bus, the **ISO** must use the weighted average of each bus' **loss factors** to determine the **loss factor** for service under Rate IOS for the Alberta – BC **intertie**; and

(c) for the Alberta –Saskatchewan **inter-tie**, calculate the **loss factor** at the bus that the **ISO** identifies.

Calculation of and Charges for Transmission Line Losses for Service Under Rate IOS and Rate XOS

9(1) A **market participant** receiving service under Rate IOS or Rate XOS of the **ISO tariff** must pay transmission line loss charges representing the average level of losses incurred in transporting electric energy on a transfer path the **ISO** identifies.

(2) The **ISO** must calculate average transmission line losses for import and export **interchange transactions** by basing the transmission line losses on the metered flow data for transfer paths the **ISO** identifies.

Calculation of Loss Factors for Service Under Rate DOS

10 The **ISO** must calculate **loss factors** for service under Rate DOS of the **ISO tariff** on the same basis as negative generation facilities.

Calculation of Loss Factors for Merchant Transmission Lines

11(1) The **ISO** must calculate **loss factors** for service over merchant transmission lines connected to the **transmission system** using the same base cases as the calculation of **loss factors** for generation facilities but must not include losses resulting from the average flow of imports and exports on the merchant transmission line.

(2) The **ISO** must model opportunity exports as a negative **generating unit** and opportunity imports as a **generating unit**.