Transmission Loss Factor Methodology And Assumptions Appendix 7

Operations & Reliability

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1. Introduction

This document is a supplement to the ISO Rule and provides details on the processes and assumptions used to calculate transmission l**oss factors**.

2. Methodology

The new **loss factor methodology** is described in the following three sections; Load Flow Loss Factors, Energy Loss Factors, and Compressed Loss Factors.

2.1 Load Flow Loss Factors (‘Adjusted’ Raw Loss Factors)

Raw loss factors are calculated for each generating unit for each base case load flow condition. Each base-case load flow is selected to represent a typical operating condition on the system, based on historical system loading conditions and historical generating unit outputs.

The twelve base cases used to determine the load flows for the **interconnected electric system** are:

- used to give snapshots of system loading conditions and losses;
- represented over each of four - “three-month seasons” of the year (winter, spring, summer and fall); and
- snapshots taken at representative peak, median and low load conditions for each season.

Generating units will be modeled in the twelve base cases using the following criteria:

- Adjustments are made to the historical power generation output if necessary to reduce imports and exports set to zero using a **generic stacking order** for generation;
- Generating units not represented in the ‘historical’ load flow model but which would be in merit according to the stacking order will be assumed to be on maintenance or forced outage;
- Generating units modeled in the load flow but not in merit according to the historical stacking order will be assumed to be generating according to market conditions, and will continue to be operated at their base case values; and
- Other generation will be added or removed to reduce exports to zero according to stacking order but recognizing any constraints imposed by the transmission system.

The methodology to determine a load flow based **‘raw’ loss factor** for one of the generating units is called the “Corrected R Matrix 50% Area Load Adjustment Methodology”. In the proposed methodology, the calculation of **raw loss factors** will be done analytically with a custom program that uses the load flow solution as a base and

computes the **raw loss factors** analytically for each generating unit in a single numerical process.
In the methodology, it is assumed:

- that the generating unit for which the loss factor is to be evaluated is going to supply the next increment in load on the AIES;
- the generating unit for which the loss factor is to be calculated becomes the swing bus for the system;
- every load within the AIES would be increased by a common factor and a loss gradient would be determined for the generating unit equal to the total change in **system losses** divided by the change in output of the generating unit for which the loss factor is being calculated; and
- the **raw loss factor** for the generating unit is set equal to ½ of the gradient.

Several assumptions inherent in the analytical method are:

- All bus voltages (and bus voltage angles) remain unchanged. This is a reasonable assumption if the magnitude of the power change is very small;
- The var component of the load is unchanged as a result of the change in MW load;
- The var output of the generating units is constant. This is consistent with the load var change assumption for small changes in generating unit output;
- The load change is applicable to only loads in the AIES;
- For i**ndustrial system** (ISD) where the ISD is receiving power, the increment in load is based on the net load at the metering point; and
- For ISD's where the ISD is supplying power, the ISD is treated as an equivalent generating unit with output equal to net to grid at point of metering.

'Raw loss factors' calculated in this manner for every generating unit (or equivalent generating unit):

- when multiplied by the generating unit output in MW and summed for all generating units in Alberta will account for almost 100% of the load flow losses for the Alberta system;
- result in a **shift factor**, required to compensate for over or unassigned losses, which is extremely small;
- do not include Small Power Research and Development (SPRD) generating units; and
- include an additional small load flow **shift factor** component compensating for the unassigned component of the SPRD generating units with distribution based on their power output in the load flow.

2.2 Energy Loss Factors

The proposed process to calculate energy–based normalized **loss factors** for each of the generating units is as follows:

- a seasonal ‘adjusted’ **raw loss factor** is calculated for each generating unit equal to the weighted average of the three ‘adjusted’ **raw loss factors** determined for each of the three system loading conditions for the season;
- the seasonal ‘adjusted’ **raw loss factor** is multiplied by the forecast generating unit volumes for each generating unit to establish a preliminary allocation of losses for each season;
- the total allocation is compared to the estimated energy losses for the system and a seasonal **shift factor** is introduced to account for any differences between allocated and estimated energy losses; and
- the n**ormalized annual loss factor** is set as the weighted average of the four seasonal shifted **loss factors**.

2.3 Compressed Loss Factors

If a situation does arise where compression is necessary, the following methodology will be adopted:

- The **loss factors** of all generating units outside of the valid range will be limited to the valid range, and
- A **shift factor** will be applied to the **loss factors** for all generating units not on the limit with the first calculation to balance the energy loss.

If any **loss factors** lie outside the range as a result of application of the **shift factor**:

- the **loss factors** of all of the generating units that were not originally on the loss factor compression limits would be ‘linearly compressed’
- the difference between the shifted loss factor and the **system average loss factor** would be multiplied by a constant factor and the result added to the average loss factor to ensure that all **loss factors** are within limit; and
- the final loss factor will be referred to as a ‘compressed’ loss factor.

A MathCAD implementation of the clipping algorithm is shown below:

MathCAD Implementation of Clipping with Linear Compression Algorithm

Clipping Plus Linear Compression

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

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 Plus Shift Factor

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

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

3. Loss Factor Procedures

3.1 Development of Base Cases

A single suite of up-to-date base cases for calculating the annual **loss factors** will apply from January through December. The base cases comprising load profiles using the **ISO load forecast** shall include:

- Peak, median, and light load cases for the three month period December , January, and February (winter season),
- Peak, median, and light load cases for March, April, and May (spring Season),
- Peak, median and light load cases for June, July, and August (summer season), and
- Peak, median, light load cases for September, October, and November (fall season).

Background: In order to meet AESO's requirement for 12 base cases to arrive at the 2006 loss factors, the duration curve (Load Duration or Generation Supply) are needed to be divided into three representative segments. These three segments are – High, Medium and Low.

The AESO's proposal for obtaining the intermediate values is as follows:

Figure 1 shows the graphic representation used in determination of the three 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 straight lines form the three segments and these three 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.

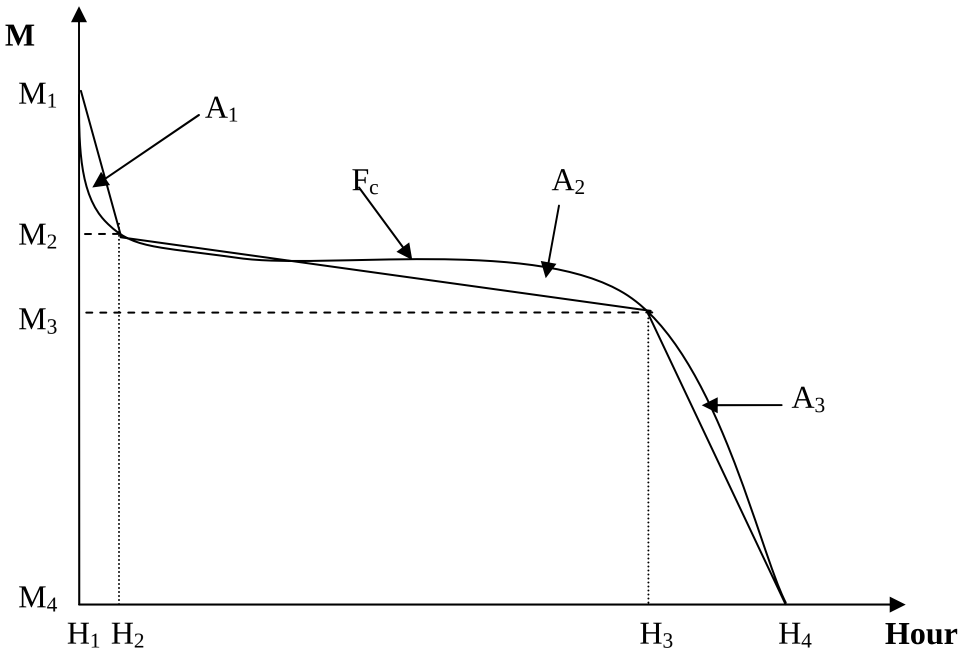

Figure 1: Graphical representation of duration curve and intermediate values.

The task is to find the intermediate hours, H_2 and H_3 and MWs, M_2 and M_3. The procedural steps of the proposal are given below.

1. For each of the segment obtain the area under the straight line and duration curve F_c.
2. Find the difference between these two areas (A_x).
3. Find all three A_xs and add their squares ($A_1^2 + A_2^2 + A_3^2$).
4. Find H_2 and H_3 so that the sum of the squares of A_xs becomes minimum ,i.e.

Minimize ($A_1^2 + A_2^2 + A_3^2$).

5. Duration of each segment will represent the weight for that segment and the average MW value for the segment will be the average MW value of the segment.

6. For High season the duration will be ($H_2 - H_1$) and the MW will be

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

Similarly the duration for Medium season will be ($H_3 - H_2$) and the MW will be

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

Similarly the duration for Low season will be ($H_4 - H_3$) and the MW will be

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

The twelve load flow base cases will include:

- All facilities that are commissioned as of December 1 of the current year and that have no Energy and Utilities Board approved plan for decommissioning prior to January 1, of the sixth year out.
- All facilities selected by the ISO to be included in all base cases for a season, must have a planned in-service date for the facility on or before the midpoint of the season. Otherwise the facilities will be included in the following season.
- All customer initiated projects (including load, generation and associated transmission facilities) that have a Customer Commitment Agreement (CCA) to be included in all base cases for a season, provided that the planned in-service-date for the facility is on or before the midpoint of the season. Otherwise they will be included in the following season.
- All ISO initiated projects for which the Board has approved the “Need” to be included in all base cases for a season, provided that the planned in-service date for the facility is on or before the mid-point of the season. Otherwise they will be included in the following season.
- Planning generating units as required for the base cases for the fifth year forecasted GSO.
- The three base cases for each season will have identical physical topology and show all projects whose in-service-date falls before the midpoint of the season.

Status of facilities (in-service or out-of-service) to be adjusted as follows:

- Normally in-service status shown on the operating single line diagram.
- Seasonally switched device status will show their normally in-service status, and be adjusted by ISO who will adjust status only as explicitly specified from the TFO.

The load flows will use 1520 (WECC equivalent bus) as the swing bus. The **ISO load forecast** to be used will be the latest approved forecast created during the current year by the ISO. The same forecast will be used to provide a set of forecast **loss factors** for the fifth year subsequent to the year referenced in the foregoing.

3.2 Development of Generic Stacking Order

A g**eneric stacking order** (GSO) will be developed each year by the ISO. The GSO shall be based on at least the following considerations:

- GSO constructed according to historical point of supply (POS) metering records.
- GSO for system peak will be based on the determination of H1-H2 and M1-M2 (in figure 1 above) for the relevant season.
- GSO for system median will be based on the determination of H2-H3 and M2-M3 (in figure 1 above) for the relevant season.
- GSO for system minimum will be based on the determination of H3-H4 and M3-M4 (in figure 1 above) for the relevant season.
- Any new generating units for which a historical record is not available will be dispatched according to the ISO's analysis of the generating unit's technology. Its power output would be based on its **Incapability Factor**. Industrial system generation and hydro generation to be re-dispatched accordingly.

ISO will develop additional base cases for the calculation of Opportunity Service including Opportunity Imports, Exports, and Demand Opportunity Service.

3.3 Calculation of Loss Factors

The ISO will calculate the **loss factors** for each year using the base cases developed for Firm Service and the additional base cases developed by the ISO for Opportunity Services. For calculation of loss factors for firm service, the ISO will adjust the resulting generation dispatch according to the GSO to achieve a zero MW exchange at all inter-ties.

3.3.1 Loss Factors for Firm Service

In the proposed process in developing the twelve base cases for **loss factors**:

- the ISO would use historical production data to determine the power level to be used for existing generating units;

- STS contract levels for new generating units;
- each base case contains its own dispatch order based on a common annual stacking order; and
- the stacking order stays the same in each base case with respect to the order of dispatch, but the amount of power dispatched by each unit varies because of seasonal considerations.

The ISO, through discussions with owners of new generating units:

- would add the new generating unit to the existing stacking order;
- base its power output on its **Incapability Factor** where the **Incapability Factor** (ICBF) = 1 – Available Capacity Factor (ACF);
- would establish the same loss factor as existing units if the new unit is an addition to an existing plant using the same connection configuration;

The base cases used to calculate the **loss factors** for the generating units would all contain a zero value for the exchange across the inter-ties. **Loss Factors** calculated with inter-ties set to zero power flows reflect the losses associated with the supply of energy for domestic load.

3.3.2 Loss Factors for Firm Import Service (not currently available)

Determination of a loss factor for Firm Import Service will be calculated with the contracted value of the transaction (in MWs) represented as a generating unit located at the appropriate inter-tie border. The base cases used for the determination of STS **loss factors** will be modified to include the firm import transaction. This contract loss factor will apply to all transactions not exceeding the contract limits for the party requesting firm import service.

3.3.3 Loss Factors for Opportunity Import/Export Service

The following conditions for Opportunity Imports and Exports will apply:

- export transactions will be represented as a negative generating unit on the appropriate inter-tie at the Alberta border;
- import transactions will be represented as generating units on the appropriate inter-tie at the Alberta border;
- the base cases used to determine the system **loss factors** would be adjusted to include the proposed transaction(s) and the **loss factors** for the export or import will be calculated;
- the import and export levels for loss calculations will be calculated as annual numbers and based on a weighted average of the forecast transactions for the year; and
- **loss factors** for opportunity import and export transactions are subject to compression.

3.3.4 Loss Factors for Demand Opportunity Service (DOS)

Loss Factors for DOS are location based and are calculated:

- on a seasonal basis;
- based on the three load cases for each season;
- with the inter-ties set to zero exchange; and
- as a negative generating unit.

DOS **loss factors** are subject to compression, i.e. DOS **loss factors** can not exceed the loss factor envelope of three times system average losses.

3.3.5 Loss Factors for Merchant Transmission Lines

The **loss factors** for merchant lines connected to the Alberta grid will be calculated using the same base cases as the calculation of **loss factors** for generating units. The twelve base cases used would contain zero exchange across each inter-tie. Opportunity Exports would be modeled as a negative generating unit and opportunity imports would be modeled as a generating unit. The **loss factors** would be location based. If the merchant line has a mid-terminus within Alberta, it would be treated the same as the end of the line (terminus), i.e. imports as generating units and exports as negative generating units. A merchant line will be treated the same as existing inter-ties.