



Transmission Loss Factor Methodology And Assumptions Appendix 6

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1. Introduction

This document is a supplement to but a part of **rule 9.2** and provides details on the processes and assumptions used by the **ISO** to calculate transmission **loss factors**.

2. Methodology

The **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 of twelve base case **load** flow conditions. Each base-case **load** flow is selected to represent a typical operating condition on the **transmission system**, based on historical system loading conditions, historical inter-tie flows, and only historical outputs of existing **generating units**.

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

- used to give weighted average values of transmission system **loading** conditions and losses;
- represented over each of four - "three-month seasons" of the year (winter, spring, summer and fall); and
- the weighted average values are taken at representative high, medium and low **load** conditions for each season.

Each **generating unit** will be modeled in the twelve base cases using the following criteria:

- Historical hourly settlement data (June 1 of Y-2 to May 31 of Y-1) for existing generation, demand opportunity service, export, and import only.
- New generation forecasted for application using the production profile provided by the owner prior to May 31 preceding the loss factor year. In the absence of a production profile dispatch will be determined by the **ISO's** analysis of the **generating unit's** technology using **STS** and **ICBF** levels (five year averages from the latest Canadian Electricity Association Generation Equipment Status Annual Report) for the capacity calculations.

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 **transmission 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 $\frac{1}{2}$ 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 industrial 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 **AIES**;
- 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 **normalized annual loss factor** is calculated 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 (loss factor envelope of +/- 12%) will be limited to the valid range by clipping, and
- A **shift factor** will be applied to the **loss factors** for all **generating units** not on the **loss factor** 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 (clipped) 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 on the next page.

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

$$Lf_4(Lf, E, k_{\max}, k_{\min}) := \left| \begin{array}{l} \text{Losses} \leftarrow ((Lf)^T \cdot E \\ Lf_{\text{av}} \leftarrow \frac{\text{Losses}}{\text{Sum}(E)} \\ Lf_{\text{max}} \leftarrow k_{\max} \cdot Lf_{\text{av}} \\ Lf_{\text{min}} \leftarrow k_{\min} \cdot Lf_{\text{av}} \\ \text{If} \leftarrow \left| \begin{array}{l} j \leftarrow -1 \\ \text{for } i \in 0..(\text{rows}(Lf) - 1) \\ \quad \left| \begin{array}{l} Lf_i \leftarrow Lf_{\text{max}} \text{ if } Lf_i > Lf_{\text{max}} \\ Lf_i \leftarrow Lf_{\text{min}} \text{ if } Lf_i < Lf_{\text{min}} \\ \text{if } (Lf_i \geq Lf_{\text{min}}) \wedge (Lf_i \leq Lf_{\text{max}}) \\ \quad \left| \begin{array}{l} Lf_i \leftarrow Lf_i \\ j \leftarrow j + 1 \\ \text{iref}_j \leftarrow i \\ \text{lftemp}_j \leftarrow Lf_i \\ \text{Etemp}_j \leftarrow E_i \end{array} \right. \\ \text{If} \end{array} \right. \\ \\ \text{sf} \leftarrow \frac{\text{Losses} - \text{If}^T \cdot E}{\text{Sum}(\text{Etemp})} \text{ if } j > 0 \\ \text{lftemp} \leftarrow \text{lftemp} + \text{sf} \\ \text{lftemp2} \leftarrow Lf_1(\text{lftemp}, \text{Etemp}, k_{\max}, k_{\min}) \\ \text{for } k \in 0..j \quad \text{if } j \geq 0 \\ \quad \text{lf}_{(\text{iref}_k)} \leftarrow \text{lftemp2}_k \\ \text{If} \end{array} \right. \end{array} \right.$$

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

$$L_{f1}(L_f, E, k_{\max}, k_{\min}) := \left. \begin{array}{l} \text{Losses} \leftarrow L_f^T \cdot E \\ L_{f_{av}} \leftarrow \frac{\text{Losses}}{\text{Sum}(E)} \\ L_{f_{\max}} \leftarrow k_{\max} \cdot L_{f_{av}} \\ L_{f_{\min}} \leftarrow k_{\min} \cdot L_{f_{av}} \\ K_s \leftarrow \max \left(\min \left(\frac{L_{f_{\max}} - L_{f_{av}}}{\max(L_f) - L_{f_{av}}}, \frac{L_{f_{\min}} - L_{f_{av}}}{\min(L_f) - L_{f_{av}}}, 1 \right), 0 \right) \\ \text{for } i \in 0.. \text{rows}(L_f) - 1 \\ L_{f1_i} \leftarrow L_{f_{av}} + (L_{f_i} - L_{f_{av}}) \cdot K_s \\ L_{f1} \end{array} \right|$$

L_f 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:

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

Background: In order to meet **ISO's** requirement for 12 base cases to arrive at the annual **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 **ISO's** proposal for obtaining the intermediate values for load duration is as follows:

Figure 1 shows the graphic representation used in determination of the three segments. Hours are plotted in the x-axis while **MW**s 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.

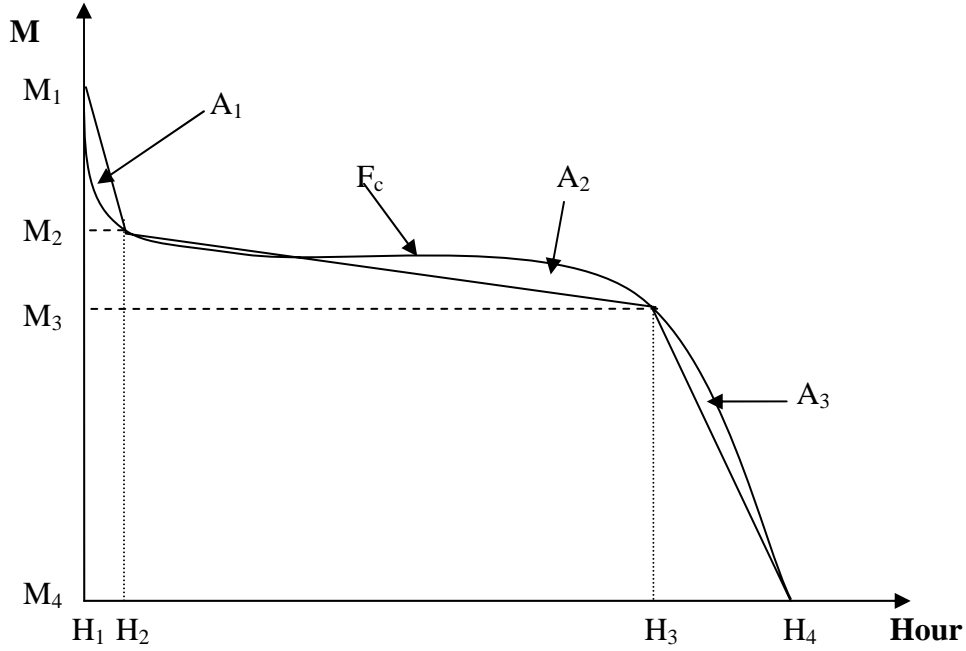


Figure 1: Graphical representation of duration curve and intermediate values.

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_x s 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_x s 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

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

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 for the forth coming year will include:

- 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 next 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 an approved Interconnection Proposal 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 **Commission** 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.
- 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.

The twelve load flow base cases for the fifth year subsequent to the year referenced in the foregoing will include:

- 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 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 an Approved Interconnection Proposal 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 **Commission** 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 and forecasted **GSO** for the fifth year.
- The twelve base cases for four seasons 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**.

3.2 Development of Generic Stacking Order

A **generic 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 for existing units.
- Determination of the four **load** points (H1, H2, H3, and H4) for the **generating unit** duration curves are selected by using the corresponding hour from the **load** duration curve for each of the seasons. For example, if H1 on the **load** duration curve for the summer season occurs at hour 1623, then H1 for each generating unit will be selected as hour 1623. The **generating unit’s** other three points on the generation duration curve (H2, H3, and H4) will be selected in the same manner.

- The **MWs** under the duration curve for points H1 to H2, H2 to H3, and H3 to H4 will be determined by the following formulas:

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

- The average value of the total **MWs** under each section of the curve will be used as the **generating unit's** output value for the associated season.
- When a shortfall of generation capacity versus system load exists in a base case, the system load will be scaled down to match supply. If necessary all twelve base cases will load adjusted.
- The ranking order for **generating units** will be the observed (historical) generator response (details in the annual **GSO** document).
- For price takers, the **loss factor** will be used to rank **generating units** within a subgroup. The **ISO** will use a maximum of two blocks of energy.
- New generation forecasted for application using the production profile provided by the owner prior to May 31 preceding the loss factor year. In the absence of a production profile dispatch will be determined by the **ISO's** analysis of the **generating unit's** technology using **STS** and **ICBF** levels (five year averages from the latest Canadian Electricity Association Generation Equipment Status Annual Report) for the capacity calculations. New generators will be added in the **GSO** according to its technology at the end of its representative group.
- The tie line and other opportunity service values will be determined in the same manner as used for generating units.

3.3 Calculation of Loss Factors

The **ISO** will calculate the **loss factors** for each year using the base cases developed for Firm Service. The base cases will contain demand opportunity services and net of export and import services for each inter-tie. For calculation of **loss factors** for firm service, the **ISO** will adjust the resulting generation dispatch according to the **GSO** to achieve the historical (previous year's) net **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 only historical production data to determine the power level to be used for existing **generating units**;
- each base case contains its own dispatch order based on a common annual **generic stacking order**; and
- the **generic stacking order** stays the same in each base case with respect to the order of dispatch, but the amount of power dispatched by each **generating 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 **generic stacking order**;
- base its power output on its production profile or the **STS** contract level;
- would establish the same **loss factor** as existing **generating units** if the new **generating 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 historical net flow for the exchange across the inter-ties. Transmission line losses across the import and export paths will be set to zero for the purpose of calculating **loss factors** for **generating units**. The **ISO** will review the base cases with owners of **generating units** to ensure that the historical data used is accurate.

3.3.2 Loss Factors for Import

The following conditions for imports will apply:

- the import **loss factors** will be calculated in the same manner as for **generating units**,
- for the Alberta - B.C. inter-tie, the **loss factor** will be calculated at the 500 kV bus #158 in the Langdon Substation; the 138 kV bus #329 at the Pocaterra substation; and the 138 kV bus #232 at the Coleman substation using historical import data and representing the import as a **generating unit**. After calculating the **loss factors** for each substation the **ISO** will use the weighted average of the three Loss Factors to determine the Import **loss factor** the Alberta – BC inter-tie.
- for the Alberta –Saskatchewan inter-tie, the **loss factor** will be calculated at the 138 kV bus #1473 in the McNeill Converter Station

3.3.3 Import/Export Transmission Losses

Importers and exporters of electric energy must pay transmission line loss charges representing the average level of losses incurred in transporting electric energy on an import path or export path. The **ISO** defines the paths as follows:

(i) Alberta – BC Inter-tie:

Tie	From Bus	To Bus
BCH	158 (LANGDON2)	90000 (1201L)
	329 (POCATER7)	819 (BRITT TP)
	232 (COLEMAN7)	1501 (NATAL 7)

(ii) Alberta - Saskatchewan Inter-tie

Tie	From Bus	To Bus
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3.3.4 Average losses for import and export transactions will be calculated as follows:

(i) Alberta – BC Intertie

- For the 138 kV circuits average losses will be determined by calculating the transmission losses based on the revenue metering data at bus 329 (POCATER7) and bus 232 (COLEMAN7) respectively.
- For the 500 kV flow path average losses will be determined by calculating the transmission losses based on the revenue metering data at bus 158 (LANGDON2)

(ii) Alberta – Saskatchewan Intertie

- Losses for the McNeill converter will be calculated based on the revenue metering data located at the Saskatchewan terminus of the inter-tie.

3.3.5 Loss Factors for Demand Opportunity Service (DOS)

Loss factors for DOS will be calculated on the same basis as negative **generating units**. **DOS loss factors** are subject to compression, i.e. **DOS loss factors** can not exceed the **loss factor** envelope plus or minus (+/-) 12 %.

3.3.6 Import 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**. Opportunity exports would be modeled as a negative **generating unit** and opportunity imports would be modeled as a **generating unit**. The import **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**.