Transmission Loss Factor Methodology

Discussion Paper

Operations & Reliability

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1. Introduction

The Alberta Electric System Operator ("AESO") is developing a new methodology for the calculation of transmission losses and the assignment of loss factors to generators connected to the Alberta Interconnected electric System (AIES). The objective of this development is to ensure that the AESO's methodology for calculating loss factors and processes are in place in the form of ISO rules that are compliant with the Transmission Regulation.

1.1 Legislative Direction

In November 2003, the Alberta Department of Energy (ADOE) issued the Transmission Development Policy Paper which proposed several significant changes to how the AESO should manage the future development of Alberta's Interconnected Electric System (AIES). In August 2004, the ADOE issued the Transmission Regulation. Section 19 of this regulation describes a new process and standard for the determination of Loss Factors assigned to generators connected to the AIES. A significant change for the AESO is that the current marginal loss methodology is not compatible with the new Transmission Regulation. Therefore the AESO needs to develop a new methodology for calculating individual loss factors for generators, imports, exports, Demand Opportunity Service (DOS), and Merchant Transmission Lines. The new methodology is to be effective January 1, 2006. The Transmission Regulation changes the way losses are treated, currently a tariff issue to becoming an AESO Rule. The AESO needs to have the new Rule approved in early 2005 so that it will be able to provide the generators connected to Alberta's grid with a set of loss factors developed using the new methodology to allow generators the ability to forecast the change in their loss charges for 2006. This is important because some generators will see a significant change in their loss factors commencing January, 2006.

1.2 Goal and Objectives

The goal and objectives of the Transmission Loss Factor Methodology initiative are:

a) To develop a loss factor methodology and cost recovery procedures compliant with the Transmission Regulation.

b) A Loss Factor Methodology to produce results that are:

- Predictable – the methodology should produce annual loss factors that, when viewed along with a fifth year loss factor forecast and the AESO's ten year transmission plan, allows owners to reasonably predict the trend for their transmission loss factors for a period of five years or more.

- Repeatable – the methodology will be able to reproduce the same results for the current year loss factors any time in the future.

- Accurate – the methodology should produce accurate loss factor numbers, such that the sum of the losses calculated by the loss factors equals the system average losses experienced on the transmission system while recognizing that forecast error is inherent in the calculation. Forecast error includes both load forecast error and production forecast error as both affect system losses.

c) Stakeholders will be consulted throughout the process of developing the new methodology and procedures for the determination of loss factors and the cost recovery of losses. Stakeholder consultation will occur at the initiation of each project milestone including the development of the principles, methodology, and the Rule making process. As part of the consultation process the project team will provide informed stakeholders with a detailed description of the methodology, assumptions and process steps being incorporated into an AESO Rule.

d) A new methodology and cost recovery procedures to be implemented into an AESO Rule by the end of May, 2005.

e) To produce a set of loss factors in the first quarter of 2005 using the new methodology. These loss factors will use the most up-to-date data available to the project team. The AESO Rule will include a date by which the annual loss factors will be issued to the generators. For 2006 a special date for the issuance of the loss factors may be required.

1.3 Provisions within the Transmission Regulation

The methodology for calculation of loss factors and its associated procedures shall be compliant with Sections 19, 20, and 22 of the Transmission Regulation. Section 21 of the Transmission Regulation describes the adjustment of loss factors by a calibration factor to ensure that the actual cost of losses is reasonably recovered through charges and credits under the ISO tariff on an annual basis. The calibration factor will be included as a rider in the AESO's tariff and simply referenced in the AESO Rule.

1.4 Loss Factor Principles

a) In order of priority, the loss methodology should:

- Provide a locational incentive for generators,

- Allow the ISO to pursue transmission projects where possible, to reduce overall transmission losses in the long term to the benefit of all consumers.

b) Owners of generation must pay location-based loss charges or receive credits.

c) The loss factor methodology should be a long-term signal and relatively stable, to allow it to be factored into investment decisions.

d) The same loss factor should apply to all generators at one location.

e) The ISO must include in the ISO tariff, transmission system loss factors that will reasonably recover the cost of transmission system losses.

f) Loss factors must apply for a period of not more than 5 years.

g) Loss factors may be revised when a system upgrade or enhancement to the transmission system materially affects system losses,

h) Loss factors may vary by location in Alberta but must be within a range of not more than 2 times system average loss factor for charges and not more than 1 times system average loss factor for credits.

i) Loss factors must be a non-variable single number at each location.

j) Loss factors in each location must be representative of the impact on average system losses by each representative generator and must be one number at each location that does not vary.

k) Importers and exporters of electric energy must pay location-based loss charges or receive credits.

l) A person supplying loads under interruptible service arrangements must pay location-based loss charges in accordance with the ISO Tariff.

m) The loss factors may be adjusted annually by a calibration factor(s) to ensure that the actual cost of losses is recovered annually and actual costs not recovered within a year may be recovered in the following year.

2. Methodology

2.1 Load Flow Loss Factors ('Adjusted' Raw Loss Factors)

Raw loss factors are calculated for each generator 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 condition.

There is no intent to deviate from the current process in which 12 base cases are used to give snapshots of system loading conditions and losses over each of the four - "three-month seasons" of the year (winter, spring, summer and fall). For each season, snapshots are taken at representative peak, median and low load conditions.

Adjustments are made to each historical Alberta power generation if necessary to reduce imports and exports set to zero. Floating the inter-ties will be carried out using a generic stacking order for generation. Generators 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. Generators modeled in the load flow but not in merit according to the historical load flow will be assumed to be generating according to market conditions, and will continue to be operated at their base case values. 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 generators has been called the "50% Area Load Adjustment Methodology" to differentiate it from other methodologies evaluated. In the methodology, it is assumed that the generator for which the loss factor is to be evaluated is going to supply the next increment in load on the AEIS. If the loss factor were calculated using a load flow program the procedure would be to set the generator for which the loss factor is to be calculated as the swing bus for the system. Every load within the Alberta electric system (or area) would be increased by a common factor and a loss gradient would be determined for the generator equal to the total change in system losses divided by the change in output of the generator for which the loss factor is being calculated. The 'raw' loss factor for the generator for the load flow is set equal to ½ of the gradient.

This process would be repeated for each generator.

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 generator in a single numerical process. This will be a significant change form the present methodology where several load flow solutions are required for each generator being evaluated.

Several assumptions inherent in the analytical method are:

a) All bus voltages (and bus voltage angles) remain unchanged. This is a reasonable assumption if the magnitude of the power change is very small.

b) The var component of the load is unchanged as a result of the change in MW load. As the proposed methodology is attempting to establish the impact of generator MW output on MW load, this is a reasonable assumption to decouple secondary var effects.

c) The var output of the generators is constant. This is consistent with the load var change assumption for small changes in generator output.

d) The load change is applicable to only loads in the Alberta system. For Industrial System Designations (ISD) where the ISD is receiving power, the increment in load is based on the net load at the metering point. For ISD's where the ISD is supplying power, the ISD is treated as an equivalent generator with output equal to net to grid at point of metering.

'Raw' loss factors calculated in this manner for every generator (or equivalent generator) when multiplied by the generator output in MW and summed for all generators in Alberta will account for almost 100% of the load flow losses for the Alberta system. The shift factor required to compensate for over or unassigned losses is extremely small. The small Power and Research Developments (generators) do not receive loss factor charges or credits and their contribution to losses is compensated for by an additional small load flow shift factor component implying that all generators are compensating for the unassigned component with distribution based on their power output in the load flow. The net shift factor due to both components is typically less than 0.1%. The raw loss factor from the load flow for each generator adjusted by the shift factor is called an 'adjusted' raw loss factor.

2.2 Energy Loss Factors

The proposed process to calculate energy –"based normalized" loss factors for each of the generators is a slight variation on the methodology used at present.

A seasonal 'adjusted' raw loss factor is calculated for each generator 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 generator volumes for each generator 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. The normalized Annual Loss Factor (Final Loss Factor) is set as the weighted average of the four seasonal shifted loss factors.

2.3 Compressed Loss Factors

With the proposed methodology, it appears that loss factor compression may not be required. If a situation does arise where compression is necessary, the following methodology will be adopted:

- The loss factors of all generators 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 generators not on the limit with the first calculation.

If any loss factors lie outside the range as a result of application of the shift factor, the loss factors of all of the generators that were not originally on 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.

The final loss factor will be referred to as a ‘compressed’ loss factor.

3. Loss Factor Procedures

3.1 Development of Base Cases

A single suite of up-to-date base cases for calculating the 2006 Loss factors will apply from January 2006 through December 2006. The base cases comprising load profiles using the AESO load forecast shall be include:

- Peak, median, and light load cases for the three month period December 2005, January 2006, and February 2006 (winter season),
- Peak, median, and light load cases for March 2006, April 2006, and May 2006 (spring Season),
- Peak, median and light load cases for June 2006, July 2006, and August 2006 (summer season), and
- Peak, median, light load cases for September 2006, October 2006, and November 2006 (fall season).

The swing bus to be used will be 1520 (WECC equivalent bus). The AESO load forecast to be used will be the latest approved forecast created during the current year by the AESO. The same forecast will be used to provide a set of forecast loss factors for a period five years out. For the 2006 loss factors, a forecast set of loss factors will also be provided for the year 2010. Base cases will be developed by the AESO. The base cases will include:

- All facilities that are commissioned as of December 1, 2005 and that have no approved plan for decommissioning prior to January 1, 2011.
- All facilities that have a planning flag set 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 customer initiated projects (including load, generation and associated transmission facilities) that have a 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 AESO 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 generators as required.

- The three base cases for each season will have identical 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 AESO who will adjust status only as explicitly specified from the TFO.

3.2 Development of Generic Stacking Order

A Generic Stacking Order (GSO) will be developed or modified each year by the AESO. The Generic Stacking Order 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 maximum (100th percentile of all metering records) output of the POS for the relevant season.
- GSO for system median (50th percentile of all metering records) output of the POS for the relevant season (considering only those POS records above some minimum threshold to be established).
- GSO for system minimum (zero percentile generation) output of the POS for the relevant season (considering only those POS records above some minimum threshold to be established).
- Any new generators for which a historical record is not available will be dispatched according to the AESO's analysis of the generator technology. Its power output would be based on its Incapability Factor. The Incapability Factor (ICBF) = 1 – Available Capacity Factor (ACF) is a standard used by the Canadian Electricity Association reflecting industry averages for each type of generation technology.
- Industrial system generation and hydro generation to be re-dispatched accordingly.

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

3.3 Calculation of Loss Factors

The AESO will calculate the loss factors for each year using the base cases developed for Firm Service and the additional base cases developed by the AESO for

Opportunity Services. For Firm Service, the AESO will adjust the resulting generation dispatch according to the GSO to achieve a zero MW exchange at all inter-ties. The Loss factors will be issued for the next year by the first Friday in November of each year.

3.3.1 Loss Factors For Firm Service

In the proposed process the AESO would use historical production data to determine the power level to be used for existing generators, and STS contract levels for new generating units in developing the twelve base cases for loss factors. Each base case contains its own dispatch order based on a common annual stacking order. 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 AESO, through discussions with new generators, would add the new generator to the existing stacking order. Its power output would be based on its Incapability Factor. The Incapability Factor (ICBF) = 1 – Available Capacity Factor (ACF) is a standard used by the Canadian Electricity Association reflecting industry averages for each type of generation technology. If the new unit is an addition to an existing plant using the same connection configuration, then it will receive the same loss factor as the existing units. The base cases used to calculate the loss factors for the generators 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. Commencing January, 2006 Loss Factors will be limited to a maximum charge of two times system average losses and credits will be limited to one times system average losses. This restriction is a directive of the Transmission Regulation (Section 19(2) (f)).

3.3.2 Loss Factors For Opportunity Import/Export Service

Alberta's transmission system currently operates under constraints (which are to be reduced under Section 2(c) of the Transmission Regulation) with respect to exports and the market currently influences when imports are likely to occur on the system. Generally imports occur at peak load periods and exports occur at median and low load periods. To calculate the import or export loss factors for a particular season, the AESO would use the base cases as follows:

- the seasonal median and low load base cases for exports,
- the seasonal high load base case for imports.

When market conditions or system topology changes allow the import and export markets to realize transactions for all hours, the AESO would use the seasonal base cases (all three load cases) for calculating both import and export losses for opportunity service.

The stacking order would be used to decrease or increase the output of the Alberta generators (to balance load and generation) to meet the requirements of the transaction(s) across the inter-tie(s). The decrease/increase in total system losses with respect to the system losses calculated using the same base cases (with a zero exchange across the inter-ties), is the losses associated with the import or export transaction. One possible solution is to have the AESO calculate the losses based on MWs for both import and export transactions for each inter-tie. From the calculations, the AESO would develop a line on a graph which would represent losses for increasing values of exports and imports. This graph will produce separate straight lines for imports and exports.

Loss factors for opportunity export transactions are not subject to compression (i.e. their loss factors can exceed the loss factor envelope of three times system average losses). Opportunity import loss factors will be treated the same as firm service and will be compressed to comply with the loss factor envelope of three times system average losses. Import transactions must not result in perverse pricing signals; i.e. an import can not receive a larger credit than a generator in Alberta located at the border.

3.3.3 Loss Factors For Demand Opportunity Service (DOS)

Loss Factors for DOS are calculated on a seasonal basis. The benchmark for seasonal system losses would be calculated based on the three base cases for each season with the inter-ties set to zero exchange. The losses associated with the DOS transaction would then be calculated for each season using the three base cases with the value of the DOS transaction added to each of the three seasonal base cases (high, median, and low load). Subtracting the benchmark system losses for each season from the respective system losses for each season with the DOS transaction equals the losses associated with DOS by season. Therefore the DOS Seasonal Loss Factor (%) would equal the DOS losses divided by the DOS transaction (MWs) for each respective season. DOS loss factors are location based and are not subject to compression, i.e. DOS loss factors can exceed the loss factor envelope of three times system average losses.

3.3.4 Loss Factors For Merchant Transmission Lines

The loss factors for Merchant Lines connected to the Alberta grid would be calculated along with the loss factors for the generators. The twelve base cases used would contain zero exchange across each inter-tie. Exports would be modeled as a negative generator and imports would be modeled as a generator. The loss factors would be location based. Merchant lines may receive loss charges or credits according to the impact of the transaction on system losses. 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 generators and exports as loads. In the case of a mid-terminus situation, a new merchant line would be treated the same as existing inter-ties. Since activity on the merchant facility may be influenced by external market conditions such as the north-west snow pack, the AESO would use a look up table with increments of power (MWs) with loss factors for each range of load or supply.

3.4 Billing

The AESO will directly enter the corporately approved loss factors into the billing system in December of each year.

4. Calibration Factor

The transmission regulation requires the AESO tariff to recover the difference between the forecast and actual costs of transmission losses through a calibration factor. The calibration factor is a deferral account and will be described in the AESO's tariff as Rider E.

Appendix A

Opportunity Import/Export Service

Introduction

The loss factor for import and export service at either the Alberta – BC inter-tie or the Alberta-Saskatchewan inter-tie is the same with opposite signs for zero power flows on the ties. With the need to use a shift factor to assign all energy to the generators, the loss factors diverge in numerical value because the shift factor which may have a negative or positive sign is added to both loss factors for imports and exports which have opposite signs. Therefore the loss factors for simultaneous transactions of import and export service do not provide reciprocity for losses and a process is required to ensure that the AESO has a fair process in place to deal with this issue. The AESO is looking at the impact of not assigning the shift factor to import and export loss factors.

Proposal A

The AESO will net out the difference in the simultaneous transaction and charge or credit the appropriate party for the losses based on the net transaction. For example:

- In hour X an import of 100 MW has a loss credit of 1% and an export of 200 MW has a loss factor charge of 3%. The next exchange is a 100MW export. Based on the formula (for Alberta-BC) a 100MW export would have a loss factor charge of 2.25%. Therefore the exporter would be charged for the 2.25% loss factor based on 100 MW. If the import transaction failed, then the export would be charged for the 3% loss factor for 200MW.

The weakness of this solution is that if there are multiple parties importing or exporting in the same hour, their total combined MWs for the hour will result in a higher loss factor being charged than would the individual transactions. Therefore parties would have difficulty determining their loss factor for their transaction ahead of time.

Proposal B

The current process for opportunity import/export loss factors assigns a single loss factor value based on the 80th percentile of the transactions conducted in the previous three month season. The advantage of this single loss factor is the certainty of the loss charge. The disadvantage is that the 80th percentile will exceed the MW size of some of the transactions, thereby resulting in higher loss factor charges than the separate individual transactions may have been attracted. For simultaneous transactions (import and export) the AESO would net out the transaction and apply the fixed loss factor to the net transaction.

- As in the example above, the net transaction is 100MW export and the export fixed loss factor for the appropriate season (Y %) would be charged to the export as 100 x Y%.