Alberta Electric System Operator

2006
Transmission Loss Factor Methodology

Decision Document

Caltech Projects Inc.

TABLE OF CONTENTS

Introduction

New Transmission Loss Factor Methodology and the Associated ISO Rule

1.0 Introduction and Background

1.1 Background

In November 2003, the Alberta Department of Energy (ADOE) issued the "Transmission Development Policy Paper" which proposed several significant changes to how the AESO would manage the future development of Alberta's Interconnected Electric System (AIES). In September 2004, ADOE issued the Transmission Regulation AR 174/2004. The policy paper describes broad objectives in the management of the transmission grid while the Regulation is prescriptive in nature. Section 19 of the Regulation describes a process and standard for the determination of loss factors assigned to Generating Units, Imports/Exports, and Demand Opportunity Services within the jurisdiction of the AIES as well as the financial settlement of transmission losses. The current marginal losses methodology is not compatible with the new Transmission Regulation. The AESO was directed to develop and implement a new methodology for calculating loss factors for January 1, 2006.

The Transmission Regulation directed the AESO to create an ISO Rule to describe the methodology and the associated processes for the determination of loss factors and the reasonable cost recovery of transmission losses occurring on the AIES. Currently transmission losses are subject to regulatory oversight with a retrospective deferral account. The AESO outlined in its 2006 General Tariff Application (section 4, p. 49-51) its proposed calibration factor methodology to recover the difference between the forecast and actual costs of transmission losses. Commencing 2006, the AESO will collect or refund the difference between forecast and actual cost of losses on a prospective basis through Rider E. The AESO proposes to file an annual financial reconciliation of transmission losses with the EUB as part of its tariff obligation for deferral accounts.

1.2 Development of a New Transmission Loss Factor Methodology

The AESO commenced a stakeholder consultation process in May of 2004 to address the need to comply with the Transmission Development Policy Paper and the draft Transmission Regulation to have a new transmission loss factor methodology in place for January 2006. AESO initially worked with IPPSA members to create a set of principles for the development of a new loss factor methodology based on the direction of the two governing documents. In late summer, the AESO expanded on its stakeholder consultation process to include organizations representing load customers.

When the Transmission Regulation was issued in September, 2004, AESO proceeded to develop a project scope and acquired the resources of Teshmont Consultants LP to assist in the determination of a methodology compatible with the Transmission Regulation and the Transmission Development Policy Paper. Initially, AESO proposed to use its formal stakeholder consultation process for the development of an ISO Rule. Based on stakeholder feedback the consultation process was lengthened to include extensive stakeholder participation in the determination of an appropriate methodology and development of the associated processes for financial cost recovery of transmission losses. Stakeholders requested the consultation process be equivalent to their prior ability for consultation as part of the regulatory oversight of transmission losses as part of the AESO's General Tariff Applications.

To date the AESO has held a total of sixteen stakeholder meeting dealing with transmission loss factors issues and four general stakeholder consultation sessions where transmission losses was one of several topics presented and discussed. Starting with January of this year, meeting notices, agendas, updates including issue papers and stakeholder meeting notes and actions have been issued through the AESO's internet mailing list to interested parties. This mailing list includes approximately thirteen hundred stakeholders. In addition to the internet mailing list the AESO project team forwarded the same information to each attending stakeholder of the project/consultation meetings, a list that numbered thirty-seven by April, 2005. All correspondence between the AESO and stakeholders including the comments from stakeholders was shared with the thirty-seven participants attending meetings. The AESO also used its formal consultation process for the development and approval for the ISO Rule. This process allowed the eleven hundred and ninety stakeholders an opportunity to comment on the proposed ISO Rule and associated Appendix.

1.3 Active Participants in Stakeholder Consultation Process

Alberta Direct Connect
AltaGas Utilities Inc.
ATCO Power
Balancing Pool
Calpine Canada
City of Calgary
ENCANA
ENMAX Energy Corporation
EPCOR Generation Inc.
Firm Group
IPCAA
IPPSA
Milner Power Inc.
NEXEN Inc.
North Point Energy Solution Inc.
Powerex
Suncor Energy Inc.
Syncrude Canada
TransCanada Energy Ltd.
TransAlta Utilities Corporation
UBS Energy Canada Ltd.

Observer status:

Alberta Department of Energy

2. Development of Transmission Loss Factor Methodology Issues

2.1 Loss Factor Principles

The AESO developed a set of principles for the development of a new loss factor methodology through stakeholder consultation. The principles were developed to be consistent with the Transmission Regulation and the Transmission Development Policy Paper.

2006 Loss Factor Methodology Principles

1. The loss factor methodology shall produce results that are accurate, repeatable, and predictable,
2. The loss factor methodology should provide a long-term generation siting signal,
3. Assigned loss factors must be a non-variable single number for generators at each location,
4. Loss factors can be changed in less than one year if the AESO determines that a system upgrade materially changes the line losses,
5. Loss factors must apply for a period of not less than one year and not more than 5 years (to increase accuracy, the AESO is recommending annual calculation of loss factors),
6. Loss factors must be representative of the impact on average system losses by each generator or group of generators,
7. Normalized loss factors shall not exceed two times system average losses for charges and one times system average losses for credits,
8. A calibration factor under the ISO tariff will ensure that the actual cost of losses is reasonably recovered on an annual basis,
9. The methodology for determining loss factors shall incorporate the best technical solution to meet the requirements of the regulation,
10. Interruptible service arrangements for load, import or export transmission service must pay location-based loss charges that recover the full cost of losses to provide this service,
11. Loss factors will be made publicly available,
12. The new loss factor methodology will be effective January 1, 2006 and,
13. Access to the Loss Factor Methodology will be provided in 2006.

2.1.1 Summary of Stakeholder Positions - Principles

Position of ATCO

ATCO offered the following opinion with regard to principle #3 “the same loss factor should apply to all generators at one location”. ATCO stated that losses do not vary linearly with generator output. As a consequence, different size generators cannot have the same loss factors if they are to be reflective of their differing impacts on system losses. This principle is therefore also in direct conflict with the s 19.2(d) requirement. Section 19.2(e) requires that there be only one loss factor at each location. This requirement is also potentially inconsistent with the s 19.2(d) requirement.

ATCO offered that possible compromises might be to use an average of the different loss factors at the location or to consider generators on different (though nearby) buses to nevertheless be at different locations. They stated it would seem that in order to meet the highest priority objective (i.e. to provide locational incentives for generators), in the event of a conflict, the s 19.2(d) requirement should hold precedence over the s 19.2(e) requirement.

Position of City of Calgary

Calgary stated loss factors that result in a credit are inconsistent with the average approach specified in s. 19(1)(b), 19(2)(d) and the specific allocation of line losses mentioned in s. 19(1)(a). Under a marginal approach it makes sense to consider that when one MW is produced at plant X that losses from plant Y go down so that plant X should receive a credit. Under an average approach however, losses should be calculated based upon the average ~5% (rounded currently) and allocated based upon actual losses attributable to each plant on a co-incidental basis:
Calgary further stated: "under the average approach almost all generators should pay for some losses – their actual losses. IF in any given hour the fact that another plant serviced a load closer to them then that should appear in the flows of that plant and their loss factor should be reduced accordingly – somewhat like what is done now. The point is that under the average approach the only generators that shouldn't be paying for some losses are those who service their own local demand/load. All others should pay for their actual losses, and if those losses are reduced by their location choice, the voltage level of their connection and/or someone locating somewhere else then bully for them and great for the consumer who sees total system losses reduced".

Position of ENMAX

ENMAX stated: "as required by 19(2)(e) of the Transmission Regulation, AESO Principle #3 states that loss factors must be a non-variable single number for generators at each location. Section 2.2.2 in the Teshmont study entitled "Loss Factor Methodologies Evaluation Simple System Testing Determination of Raw Loss Factors" contemplates an "Area Load Adjustment" methodology which appears to be based on a zone concept." ENMAX noted that certain parties have expressed continuing support for loss factor zones even though the zone concept is inconsistent with the provisions of the Transmission Regulation. ENMAX does not support the implementation of loss factor zones. They argued "according to the Alberta Government's Transmission Development Policy ("TDP"), the assignment of losses to generators was intended to provide a signal to new generation to locate in optimal areas. Zones result in cross-subsidization between generators and, contrary to the TDP, mute the signal to new generation to locate in optimal areas. In addition, zones could lead to inefficient behavior and gaming by entrants and existing generators seeking to avoid paying higher loss charges or earning greater credits." ENMAX recommended that the AESO retain AESO Principle #3 as written.
On the subject of term of the loss factors ENMAX offered the following position: In AESO Principle #4, the AESO recommends an annual calculation of loss factors for "accuracy". ENMAX recommended that loss factors be adjusted every three to five years rather than annually, as proposed. They opined that "under the AESO's annual adjustment proposal, an existing generator would be unable to avoid and would not be compensated for a material increase in loss factor charges if a new neighboring generator interconnects to the Alberta

Integrated Electric System. This unavoidable increase in loss factors resulting from the nearby interconnection does not promote a fair, efficient and openly competitive market for electricity, in accordance with Section 16 of the Electric Utilities Act." ENMAX suggested that one method of shielding existing generators from swings in loss factors as a result of the interconnecting neighboring generators would be to adjust the loss factors less frequently. They opined a three to five year adjustment, rather than annual change, would reduce the incumbent generator's expected loss factor charges due to entry.

AESO Principle #1 states that the loss factor methodology should produce results that are predictable taking into account the AESO's ten-year planning document with forecasts in load growth and system upgrades. AESO Principle #11 states that loss factors will be made publicly available. ENMAX supported allowing generators to have access to the loss factor model so that they can verify the loss factor calculations and to have the ability to produce 'what if' scenarios for future generation developments. They stated "a loss factor forecast provided by the AESO would not be sufficient to estimate loss factors for future projects given that the entrant would not know the assumptions on which the forecast was based and how different assumptions might impact loss factors." ENMAX also suggested that a three to five year fixed loss factor methodology would also give some certainty to entrants that losses would remain stable for a window of time following the generation interconnection. As such, three to five year fixed loss factors would also increase certainty for potential entrants.

Position of IPPSA

The IPPSA members initially raised the concern that the principles did not include the use of Loss Factor Zones. They were concerned that this issue had not been resolved to their satisfaction and was removed from a proposed project solution. The reason for their desire to have loss factor zones was to ensure that adjacent generators within a generation basin should have similar or the same loss factors. Until the new methodology was able to demonstrate that it could produce repeatable results and the loss factors within a generation basin were similar or the same, IPSSA was not prepared to accept the elimination of loss factor zones.

Position of TransCanada

TransCanada requested the AESO add the principle of transparency of calculations for loss factors. TransCanada wanted the ability to verify the data inputs in the twelve load flow base cases. They indicated that transparency helps stakeholders develop confidence in the loss factor calculation process administered by the AESO. They also expressed the desire to have the principle of an independent model verification of loss factors added to the overall list. Again TransCanada wanted the ability to duplicate the calculations and verify the results of the calculations carried out by the AESO. TransCanada believes the principle of providing a siting signal conflicts with providing annual loss factors.

TransCanada indicated that they supported a one year calculation of loss factors and that they no longer advocate either a zonal system or a five year lock-in period for loss factors.

Position of AESO

The AESO agrees with ATCO that the loss factors of generating units connected to the same bus should reflect the average of the loss factors of the individual generating units. Where a generating unit is physically located at the same location as other generating units and is connected to a different bus, the AESO supports assigning a loss factor that reflects that individual generating unit's loss impact on average system losses.

The AESO does not concur with Calgary's position that the Transmission Regulation only supports loss factors that are charges. The Transmission Regulation contemplates loss factor credits as demonstrated in the following section of the regulation.

Section 19(1)(c) states:
"establish a means of determining, for each location on the transmission system, loss factors and associated charges and credits, which are anticipated to result in the reasonable recovery of transmission line losses;"
Section 19(2)(f) states:
"after determining which loss factors result in a charge or credit, every loss factor must be multiplied by a common number in order to limit the loss factors as follows:

(i) loss factors associated with a charge must not exceed 2 times the average transmission system loss factor, and

(ii) loss factors associated with a credit must not exceed one times the average transmission system loss factor."

In addition, the calculation of individual generating unit's loss impact on average system losses does not preclude loss factors that are credits. Although every generating unit's output results in the creation of transmission losses, their impact on average system losses can be a reduction in total system losses.

The AESO concurred with ENMAX that Loss Factor Zones were inconsistent with the Transmission Regulation specifically Section 19(2)(d). The AESO also provided a calculation of loss factors for 2010 using two load flow base cases. The results which include the impact of the 500kV addition between Edmonton and Calgary provided sufficient information to satisfy the concerns of IPPSA members regarding the stability of the methodology. The majority of members agreed to drop the requirement for Loss Factor Zones.

The AESO does not agree with ENMAX regarding the term of the Loss Factors. There are two reasons for considering a one year term for loss factors. The first reason is best demonstrated by the current methodology where generating units located in the same geographical area; connected to the same transmission circuits; and having similar sized generating capacities have very different loss factors because of the timing of their connection to the transmission system. The resulting difference in loss factors results in a non-level playing field for the owners of the generating units. The second reason is that over time the fixed loss factors do not reflect the impact of the generating units on system losses resulting generally in an under-recovery of costs. The Calibration Factor which is the deferral account for transmission losses will grow in size over time such that it becomes a significant factor in the consideration of the cost of transmission losses for generating units. This will make it difficult for owners of generating units to forecast their individual costs for losses thereby defeating any advantage of having a fixed loss factor for a period of years. The AESO has committed to determine annual loss factors as well as providing

a non-binding forecast loss factor for the year five years forward. The intent of forecasting loss factors in future years is to provide participants with an indication of the possible change in loss factor values going forward.
In response to stakeholders' requests, AESO has committed in writing to provide stakeholders with options for access to the loss factor data and calculator. AESO does not believe that this commitment needs to become a principle of the loss factor methodology development.

2.2 Loss Factor Methodology

The new loss factor methodology is described in the following three sections; Load Flow Loss Factors, Energy Loss Factors, and Compressed Loss Factors. The methodology is referred to as "Corrected Gradient 50% Load Area Adjustment".
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 condition. Each base-case load flow is selected to represent a typical operating condition on the transmission 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 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 peak, median and low load conditions for each season.

Each generating unit 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;

- Other generating units will be added or removed to reduce exports to zero according to the generic stacking order but recognizing any constraints imposed by the transmission system.
- Adjustments are made to historical data to correct for major maintenance outages, and major forced outages.

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 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 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.

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.

2.2.1 Summary of Stakeholder Positions

Position of AltaGas

AltaGas believes that the recommendation by Teshmont of the "Corrected R Matrix 50% Area Load Adjustment Methodology" does a good job of balancing the realities of the AIES with the restrictions imposed by the regulation, and would therefore support the AESO proceeding with its implementation. We also note that Teshmont has no stake in the results of whichever methodology is chosen, therefore their recommendation can be considered unbiased.
AltaGas indicated it has concerns about excluding TMR from loss factor calculations. TMR has been a fact of life in Alberta for many years, and will continue to be in the foreseeable future. Ignoring this reality in the calculations may lead to under or over-recovery of costs, and therefore increase the need for rate riders, which has been a long-standing concern for AltaGas. They are also concerned that excluding TMR violates the requirements of the regulation 19(2)(c) to determine loss factors "as if no abnormal operating conditions exist".

Position of ATCO

ATCO disagreed with the AESO's interpretation of "Accurate…such that the sum of the losses calculated by the loss factors equals the system average losses experienced on the transmission system…" In their view, this was not a meaningful indicator of the accuracy of the loss factors. They stated "the simplest method for achieving that goal would be to charge all generators the average system loss factor. That approach would not send any locational signals or be reflective of the impact on average system losses by the generator and thus would neither address the highest priority principle (meaningful locational signals) nor meet the requirements of section 19.2(d) the regulation (reflective of the generators impact)."

In order for the proposed summation to work over a range of generator outputs, ATCO stated that the system would need to be linear. Because losses do not vary linearly with generator output they felt that this objective was in direct conflict with AESO's project principles and the requirement of section 19.2(d) of the regulation.

ATCO suggested that:

- this objective be replaced by a more general one; that losses charges to generators equal the cost of losses experienced on the transmission system; and,
- the magnitude of the "shift factor" not be used as a measure of the accuracy of the methodology.

The proposal is to use the "50% Area Load Adjustment Methodology" whereby 50% of the marginal loss factors (gradients) are to be used as the raw loss factors. ATCO raised concerns that "this methodology will not produce results that provide meaningful locational signals or represent generators' impacts on average system losses. They are concerned that the objectives chosen to select a methodology were flawed or superficial and that this has resulted in selection of a methodology that is not aimed at accurately achieving the highest priority principle (i.e. to provide a locational signal) in a manner that satisfies the regulation." ATCO stated "the proposed methodology, a marginal methodology won't predict the impact of the generator, only of the last megawatt generated."

ATCO concurred with the AESO that a fundamental difference between the parties is the notion of whether or not the location based signals (and thus the loss factors) should look "only to the future". ATCO stated that the AESO has made no attempt to reflect the impact of siting decisions already made in their proposed loss factor methodology and associated processes. They referenced Section 19.2 (d) of the Regulation which states: "the loss factor in each location must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load."

They opined that a generator's impact on average system losses cannot be the impact of the next MW of output (or one half of the next MW). It must be the impact of the MWs that are actually running. ATCO stated loss factors that are representative of generating units' impact on average system losses cannot look "only to the future". ATCO proposed an alternative methodology which they believed provided an accurate representation of the individual impacts of generating units on system losses. Their preferred methodology is the "Incremental Loss Factor methodology". Included in Appendix A is the correspondence and analysis of two and four bus examples of loss calculations provided by ATCO. In addition ATCO's proposed Incremental Loss Factor methodology analyzed by Teshmont is included in the Appendix.

Position of Calpine

Initially Calpine supported the proposed loss factor methodology. Later Calpine expressed concern that the proposed loss factors do not "reflect the impact each generator has on average system losses" as prescribed by Transmission Regulations. Furthermore, in certain cases, the loss factors derived from the proposed methodology fail to deliver any location signal. Also, the proposed loss factors do not result in the same loss factor for generators having same magnitude of impact on system losses as required by Transmission Regulations.

Calpine is concerned that the proposed loss factors may lead to higher volume of annual system losses since it benefits generators that contribute to higher system losses. If the shift in loss factor is sufficient to produce change in stacking order, the impact will be suboptimal generation dispatch and, consequently, higher system-wide electrical losses. Calpine respectfully requests that AESO address this issue in detail prior to the adoption of the methodology.

Calpine shares concern first advanced by H.R. Milner with selection of criteria for valuation of loss factor methodologies. Calpine is in particular concerned with adoption of requirement of low shift factor as the primary criteria. It has been assumed by various parties for some time that large magnitude of shift factor indicates "inaccuracy" in the methodology itself. Such criticism fails to consider that loss factor tariff is a cost allocation mechanism. As such, it can meet its design objectives well, somewhat or not at all. The design objectives should be similar to those

used when designing any tariff. The design objectives have to also reflect and comply with the applicable regulations and laws.
In the above respect, the objectives of low shift factor has little practical benefit since any methodology that produces a tariff that directly recovers system average losses without adjustment would score high on the list. Example of such a methodology is a postage stamp rate. Also, any methodology that uses an "internal" or hidden adjustment factor will score high. An example of the latter method is the proposed methodology that uses hidden adjustment factor of 50%. Virtually any methodology that uses internally hidden adjustment factor can be "forced" to recover average system losses by suitable selection of the hidden factor and hence declared as shift factor free."

Position of ENMAX

ENMAX recommended that power flow models and extraction/processing routines be provided to generators by the AESO as soon as they are available so that they could check the AESO's calculations of loss factors as well as undertake any "what if" analysis on their own for future generation additions. ENMAX noted that the proposed 50% Area Load Adjustment Methodology is independent of a single swing bus; minimizes the calibration factor; is location-based rather than zone-based; results in the correct loss factor "stacking order;" and, addresses the issue of double counting of the loss charges for exports. For these reasons, ENMAX indicated it was not opposed to the implementation of the 50% Area Load Adjustment Methodology to calculate loss factors.

Position of EPCOR

EPCOR supported the Transmission Development Policy Paper proposal to limit any one time change in loss factor to individual generators to not more than 1/2 of the system average losses. They also indicated support for the AESO providing a mechanism whereby market participants can access the loss factor model and do their own sensitivity or planning runs. EPCOR stated that they supported the use of a firm one year loss factor calculation with a forecasted loss factor for a fifth year forward. EPCOR did not support the use of loss factor zones.

Position of Milner Power

Milner Power has opined that the proposed methodology does not fairly reflect generating unit impacts on average system losses. Their concern is the AESO's proposed loss factor methodology evaluates the impact on system losses of the last MW of production from a generator and then divides this by two. Using this approach, the sum of all losses recovered from all generators will closely match the forecast volumes of transmission losses. They have stated while loss factors based on the Marginal Loss Factor (MLF) of the last mw-in divided by two (MLF/2) recovers the correct amount of transmission losses on an aggregate or global basis, it fails in many cases to recover the correct amounts on a generator-specific basis. The MLF/2 approach does not approximate and significantly prejudices those generators whose output creates a net reduction in system losses. As the calculation and apportionment of losses is a zero sum game, those generators most responsible for system losses are benefiting at the expense of those generators most benefiting the system through loss reduction.

Position of TransCanada

TransCanada stated that loss factor models should be provided in October for the upcoming year to allow stakeholders to agree on the assumptions and loss factor modeling changes. Once the loss factor modeling changes have been vetted by stakeholders, the final loss factors should be published by the AESO in November.
Regarding the Milner proposal for exclusion of generator TMR dispatch from load flow cases, TransCanada is opposed to this proposal for these reasons:

1. “The AEUB has suspended the Article 24 and Section 23 price cap debate to a hearing September 19, 2005. This has been a controversial matter between the generation community and the AESO. The outcome of this debate could materially affect the amount of generation that is considered TMR generation, particularly in the Calgary area (the AESO currently assumes in-merit generation does not need to be dispatched as TMR generation even if the system requires TMR). The assumption in the Milner proposal, "other areas of the province occasionally rely on TMR dispatch" may not hold over the next few years. The AESO has recently initiated a Calgary area RFP. Removal of large amounts of TMR generation from the Calgary area as proposed by Milner would lead to a major distortion of the power flows and the actual losses being incurred.
TransCanada agrees with AltaGas that the Milner proposal is not in conformance with Section 19(2) (c) of the Transmission regulation. This occurs in several ways, by excluding TMR MW, but not excluding TMR MVARs, by scaling the system load down to match the generator TMR MW removed from the generic stacking order and using TMR MVARs as a "proxy" for plant that doesn't exist. Milner assumes that because a TMR generator is entitled to loss factor recovery when dispatched under TMR and other generators do not get similar treatment that this has distorted prices. This may not be the case as the price negotiated for TMR service will likely have included the guaranteed recovery of losses in the price (in a similar way that IBOC generation price offers took into account their loss determinations on a first MW in basis through the offer prices).”
TransCanada requested that the AESO evaluate the Flow Tracking loss factor methodology. They stated the ABB Study on loss factors indicated that the Flow Tracking methodology was ranked as a good methodology.

Position of AESO

In order to provide generators with the ability to verify the loss factor calculations and to have the ability to produce ‘what if’ scenarios for future generation development, the AESO has contemplated either:

- Licensing a third party consultant to provide this service; or,

- Providing special web access to stakeholders to allow generators direct access to the loss factor model.

AESO will provide business cases for both options including required funding and present the options to stakeholders prior to year end.

The Transmission Regulation does not include the principle "to limit any one time change in loss factor to individual generators to not more than 1/2 of the system average losses"; therefore AESO is not proposing to use this principle. An addition of a significant transmission facility could result in a loss factor change for a particular generator which could exceed the 0.5 times system average. However such an addition to the system would reduce the losses overall and in particular the loss factors to directly connected generating units, units that would see their loss factors being impacted by the system upgrade.

AESO's comments on "Summary of Milner Power's Concerns with the proposed Loss Factor Methodology:

AESO believes that the summary may be oversimplifying the proposed loss factor methodology. The proposed AESO methodology is based on load flow losses as well as cumulated energy losses. The methodology is not based on a "last MW-in approach" as adopted in the current methodology. Total system losses are determined for 12 representative snapshots of the system based on 'actual' projected operating conditions. Individual generator output for each snapshot will be based on historical performance of each unit. If historical records indicate that a generator has operated at close to 100% output continuously, it will be modeled at close to full output in all of the 12 load flow cases. If a unit has shown to be operating at full output for only 50% of the time, (shut down for the rest of the time), roughly ½ of the load flows will the modeled with the unit at full output. The remaining load flows will represent the unit with no output. A more appropriate description of the basis for the methodology would therefore be "actual MW in approach".

Loss factors are calculated for each load flow condition, and for each generator based on 1/2 the impact of the next incremental output from each generator. Load is adjusted to accommodate the change in generation and losses. It can be shown that with this calculation method, the sum of product of the individual generator output and its loss factor accounts for almost 100% of the total system losses. The impact of system load on losses (which all generators must account for per the regulations) is automatically assigned to the generators. Simulations have shown that the approach assigns close to 100% of the total system losses for a two-bus system up to a 2000 bus model of the AIES.

The Flow Tracking method as proposed by TransCanada Energy was evaluated by Teshmont and the results are as follows:

• Based on a full system test, the flow tracking methodology fails when situations arise where a generator is small but the var flow in adjacent circuits are large. Such would be the case for units connected primarily for voltage control or for small units connected close to buses with large capacitors. A solution could be to ignore loss factors for small units, but this would require some formula to decide under which situation a unit should be ignored. This will be more complicated than simple MW criteria as Mvar to MW ratio comes into play.

• Load flow accuracy appears to be important for the methodology. Smaller magnitude branch losses are less accurate resulting in less accurate loss factors related to those losses.

• With the methodology there are no credits and all load buses or buses with generation less than load will be assigned a loss factor of zero. This will make it necessary to adopt another methodology for export and DOS loss factors.
• The compressed loss factor range will be less than twice system average or less than 2/3 of the range targeted by the DOE. If an evaluation factor (penalty) for a range less than this was to be included to represent strength of generation signals, the methodology would rank low (i.e. not attractive) in the evaluation matrix with a large number of generators outside of the limits and a large loss factor range.
AESO will have a ranking matrix available in the next couple of days if required.

2.3 Development of Load Flow 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).

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 Board approved plan for decommissioning prior to January 1, of the second 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.
- 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 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.

2.3.1 Position of Stakeholders – Load Flow Base Cases

Position of ENMAX

ENMAX supported allowing generators to have access to the loss factor model and sufficient technical information so that they can verify the loss factor calculations and to have the ability to produce 'what if' scenarios for future generation developments. As such, ENMAX did not object to including any of the information (use of historical metering data; use of scheduled generator maintenance outages, available through the MSA; transmission system additions; and, new generators) in a publicly available loss factor model.
With respect to new generators, ENMAX submitted that until the potential generator has signed a Construction Commitment Agreement, there is significant uncertainty whether the generator will be built. As such, the AESO should not include this information in the losses model and it should not be made public.

Position of Milner Power

Milner Power argued for the exclusion of generator TMR dispatch from the Loss Factor Calculations. A summary of their argue follows. "The Northwest area relies on transmission must run (TMR) units to provide voltage support and reliability. Other areas of the province occasionally rely on TMR dispatch of generating units. TMR causes generators to run that otherwise would not. The forced generation mutes the imbalance between generation and load in an area. This artificially reduces loss credits and increases loss charges in areas where additional generation is needed.
Generators providing TMR can recover the costs of loss factors from the AESO. However, generators in the area that are not providing TMR are not insulated from the effect of increased loss factors. To the extent that the generators providing TMR cause the loss factors applied to other generators to be higher, generator costs are distorted and the locational incentive of the loss factor is artificially diminished.
To separate the treatment of TMR from loss factor issues Milner Power proposed that generator TMR dispatch be excluded from the Loss Factor Calculations. Their proposed mechanism to do this is:

- Remove TMR MW dispatches from the generic stacking order.
- Maintain the MVAR capability of the TMR generators in the load flows used to determine loss factors.
- Scale the overall system load down to match the generator TMR MW removed from the generic stacking order.

By removing the TMR MW dispatches from the generic stacking order, the generator loss factors will not be distorted by generation that would not normally be dispatched absent a TMR directive from the AESO. Removing the TMR MW dispatches while retaining the MVAR capability of TMR generators will aid in insuring the resulting load flow cases will solve. The MVAR capability provided by generators is a proxy for reactive support that would be provided by additional transmission reinforcements in the absence of the TMR generators. Scaling the overall system load down to match the generator TMR MW removed is consistent with the principle that system load and generation should increase and decrease together. This approach avoids the need to re-dispatch other generators in the stacking order or to determine where the generation dispatched to meet TMR would normally be dispatched in the stacking order." Milner Power also stated "the Transmission Development Policy envisions the removal of transmission constraints and hence minimizing the need for TMR. Thus in the longer term the need for TMR dispatches should be reduced and the exclusion of the TMR dispatch from the Loss Factor calculations would have little or no impact on the resulting loss factors applied to generators."

Position of TransCanada

For simplicity, TransCanada indicated a preference for the AESO using historical data for the most recent months when developing a calculation of losses by generator location. TransCanada also supported the use of the MSA's one year forecast for scheduled maintenance outages. TransCanada supported the development of a non-binding forecast of loss factors for five or ten years forward. They stated that this forecast was important to their business planning capability.

The AESO proposed that customers with signed CCA agreements for a new or expanded point of delivery or supply be added to the loss factor models. TransCanada agreed with this process for loss factor forecast in future years. For the year in which the billable loss factors are to be determined, only points of delivery or supply with approved System Access Agreements should be added to the loss factor model. Additions to one or more of the 12 loss factor models (load flow base cases) should be based on the in service date in the System Access Agreement.

The AESO proposes to include planning generators to the load flow base cases when needed. In TransCanada's opinion, planning generators can be added as required in forecast modeling in future years but should be specified within the summary of changes to the model with reasons as to why the generators were added. No planning generators should be added to the models for the billable loss factors.

Position of TransAlta

The AESO should provide more information on the development of the peak, median, and light load base cases in the Transmission Loss Factor Methodology Discussion Document. The information provided should be similar to the report Loss Factor Methodologies Evaluation Part 2 – Conversion of Power to Energy Loss Factors which provided the mechanism of averaging for the high, mid, and low sections of the load duration curve.

Position of AESO

The AESO does not support the removal of TMR from the load flow base cases. A detailed explanation can be found in Appendix A of this document under Section 3.1 AESO's Response to Milner Power. The AESO considers the addition of new generators to the following year's base cases when the owner has a signed Construction Commitment Agreement or, in the case of small wind units, the proponent has demonstrated that there is a strong likelihood that the unit will be installed in the next year.
In response to TAU's request, the AESO has produced a detailed mathematical model and explanation on how the high, median, and low base cases are determined. This information can be found in Appendix B of this document under the ISO Rule Document titled "Transmission Loss Factor Methodology and Assumptions Appendix7" in Section 3.1 Development of Base Cases.

2.4 Generic Stacking Order

A generic stacking order 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.
- 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 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.
- The ranking order for generating units will be the observed (historical) generator response.
- For price takers, the loss factor will be used to rank generating units within a subgroup. The ISO will use two blocks of energy.
- 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.

2.4.1 Position of Stakeholders, Generic Stacking Order

Position of EPCOR

EPCOR Merchant and Capital L.P. indicated that they were not prepared to make EPCOR's planned outage information publicly available in advance even if only on a seasonal basis. They stated that will increase the level of assumptions that stakeholders will need to make in order to replicate future loss factor calculations. However, historical outage patterns and the MSA total MW out by fuel source should help to produce reasonable GSO base case.

Position of TransCanada

Using the 100th percentile on marginal MW in the generation stacking order (GSO) is not consistent with the average method used in determining the seasonal capacity. It is their understanding that the average method for determining the seasonal peak was as per figure 3 in the report Loss Factor Methodologies Evaluation – Part 2 – Conversion of Power to Energy Loss Factors. In this report, the peak is the average of the 66th to 100th percentile, median 33rd to 66th and low 0 to 33rd percentile on the load duration curve for the season. TransCanada recommended that the average method be used to determine the seasonal capacity also be used to develop the GSO. The AESO would produce 12 generator outputs in the GSO table for each generator that corresponds to the 12 loss factor models. TransCanada believed that this recommendation provided for greater consistency within the approach taken by the AESO and better conforms to the Transmission Regulation, Section 19(2)(d) that "the loss factor in each location must be representative of the impact on the average system losses by each respective generating unit or group of generating units relative to load".

Modeling of new generators should be similar to the modeling of existing generators. Since the historical output of the new generator is zero, assumptions should be made by comparing the historical operation of similar generators with some allowance for commissioning requirements and planned operation of the generator. STS contract levels should not be used to model new generator output. Assumptions for new generators should be provided by AESO in the GSO tables and loss factor models.

AESO Response

The AESO has agreed to not use the MSA's annual forecast of maintenance outages for generating units. The historical data of generating unit outputs will be used without modification except where owners declares a change in operating practice for the generating unit(s). The determination of high median and low base cases was discussed in the previous section of this report. New generating units will be modeled based on historical data available from the Canadian Electricity Association's database with input from the proponent.

2.5 Compression of Loss Factors

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

- The loss factors of all generators outside of the Regulations prescribed range will be limited to that range.
- A shift factor will be applied to the raw loss factors for all generators not on 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 loss factor will be compressed and then referred to as a final loss factor.

2.5.1 Position of Stakeholders, Compression of Loss Factors

Position of AltaGas

AltaGas expressed concern that the proposed loss factor compression methodology limits loss factors of all generators outside of the valid range to the valid range and applies shift factors to the loss factors for all generators not on the limit with the first calculation. This appears to AltaGas to be inconsistent with the Transmission Regulation, which requires, in Section 19 (2) (f), that "every loss factor must be multiplied by a common number in order to limit the loss factors as follows: . . " The concept of a shift factor to generators not on limit is inconsistent with this. AltaGas suggested that the AESO could either have the Transmission Regulation changed to reflect the proposed methodology and develop a compression methodology consistent with the Transmission Regulation.

Position of TransAlta

TransAlta indicated that the method for compressing loss factors may be in violation of the Regulation. TransAlta requested confirmation whether this was the case and if so how will the AESO propose to deal with this issue.

Position of AESO

Teshmont was unable to develop a compression methodology that produced acceptable results and remained compliant with the Transmission Regulation. The proposed model for loss factor compression is the model recommended in the Teshmont Report " Loss Factor Methodologies Evaluation Part 3 – Loss Factor Compression" dated January 26, 2005. The AESO will advise the Alberta Department of Energy that the AESO is proposing to use a compression methodology which is non-compliant with Section 19(2) (f).

2.6 Opportunity Services

AESO proposed the use of 50% area load methodology for generators' loss factor calculation in Alberta starting from 2006. The methodology calculates the average impact of each generator's contribution on the total system loss. The average impact is calculated from the marginal impact by dividing the latter by 2. This methodology is applicable for Alberta generators only. However, there are some opportunity services (OS) such as export, import and DOS in Alberta whoare required to pay for losses as well. They will pay for the total losses their transactions cause as opposed to average loss. This requirement is documented in the Transmission Regulation Section 22**(2)** "A person receiving transmission service under an interruptible service arrangement for load, import or export must pay location-based loss charges that recover the full cost of losses required to provide this service".

The methodology for calculating loss factors for Opportunity Services is described in Appendix C, Technical Reports For the Proposed Loss Factor Methodology titled "Loss Factor Methodologies Evaluation Part 4 – Determination of Opportunity Services "Raw" Loss Factors.

2.6.1 Position of Stakeholders, Opportunity Services

Position of AltaGas

AltaGas expressed concerned that the ISO rules are not be compliant with the Transmission Regulation, which requires, in Section 22(2) that exports "must pay location-based loss charges that recover the full cost of losses required to provide this service." AltaGas expressed concern that if there is not an offsetting credit or similar mechanism, there may be double-counting of losses for exports. In addition, AltaGas does not believe that the current proposal deals appropriately with equal and opposite factors for counter-flows.

Position of ENMAX

In the Loss Factor Methodology Discussion Paper, the AESO outlined the following two options for loss factor treatment of export service:
Proposal A contemplates the AESO levying the appropriate party a charge or credit for the losses based on a net import/export transaction. Under this proposal, loss factors for exports would be dependent upon aggregated exports and the loss factor would be calculated on an ex post basis.
Proposal B assigns a single loss factor value based on the 80th percentile of the transactions conducted in the previous three month season. Proposal B appears to be less accurate than Proposal A but does provide visibility to the loss factor prior to export.
ENMAX opined that it is essential for exporters to understand the credits and charges that they will incur prior to transacting, and believes that improved accuracy is also important; therefore ENMAX proposed a combination of Proposal A and B.
Proposal C is to utilize Proposal B, and in order to improve the accuracy of Proposal B a separate reconciliation process for import and export losses could be considered. Over and under-

collections for export/import losses could be added or subtracted from the export loss factor for the next adjustment period. This would result in exporters as a group paying the correct amount for losses over time. ENMAX notes that this plan would likely require Rider E, as contemplated in the AESO 2006 General Tariff Application, to be amended.

In addition, calculating a separate loss factor for on-peak and off-peak periods would increase the accuracy over a single loss factor for all periods.

Section 22(2) of the Transmission Regulation states that “a person receiving transmission service under an interruptible service arrangement for load, import or export must pay location-based loss charges that recover the full cost of losses required to provide this service.” ENMAX stated that calculating loss factors for opportunity export service results in a double counting of the loss charge. Consequently, ENMAX supports a loss factor model that minimizes the loss factor charge or credit that applies to exports. This would ensure that exporters will not be unfairly overcharged for exports.

Position of IPCAA

IPCAA is concerned that any compression of loss factors for opportunity export service will unfairly result in load customers sharing in the costs related to the supply of export service.

Position of TransCanada

TransCanada would like the AESO to consider having one annual loss factor for export and import. Since it is not clear from the information provided that the accuracy of the loss factor would be acceptable at an annualized level, TransCanada would like to see how much accuracy is lost if annual loss factors were used. From the document provided by the AESO, Inter-tie Loss Factors, it appears that the extreme export loss factors of 15% to 25%n would not occur with the new loss factor methodology. These smaller loss charges may allow for some averaging to simplify the import and export tariffs, the AESO could use historical export and import capacity. For each hour, the net export or import would be determined by setting the peak as the average of the 66th to 100th percentile, median 33rd to 66th and low 0 to 33rd percentile of the import or export load duration curve. Exports would be modeled as negative generation and as such would be modeled in the opposite manner to generators (low exports would be modeled with high load and high generation in Alberta and high exports would be modeled with low Alberta load and low generation). TransCanada would suggest that AESO calculate import and export loss factors using the 12 average export and import capacities to determine if the loss factors are reasonably stable for all seasons of the year. This would be the basis to determine if loss factors can be simplified into an annualize amount, which in turn would be consistent with how generators are assessed losses.

Position of TransAlta

There was a concern expressed that losses were being double counted with respect to exports. From what TransAlta saw in the February 9, 2005 Loss Factor Methodology Discussion Paper this concern had not been addressed and if necessary rectified by the AESO.

TransAlta noted that Section 3.3.4 of the February 9, 2005 discussion paper dealt with loss factors for merchant transmission lines. As there are no merchant transmission lines presently in

Alberta, TransAlta asked whether it is necessary for the ISO Rule to include a definitive loss factor methodology for merchant transmission lines or would a more general approach be more appropriate at this time?

Position of AESO

The AESO does not believe that it is practical to modify Rider E such that the deferral account is reconciled every three months. AESO has considered ENMAX's request about visibility of loss factor charges prior to processing transactions. The AESO is proposing to use a single annual loss factor for imports and exports. A report on the import and export loss factors is contained in Appendix C.

2.7 Calibration Factor

The AESO's expected process for determining calibration factors is summarized in the following Table. The calibration factor is the process used to correct for the difference in the cost of losses recovered through the billing system based on the loss factor values and the actual cost of losses measured by the Point of Supply (POS) and Point of Delivery (POD) revenue meters. This deferral process will be prospective with the target being that the actual cost of losses is recovered within the year the losses occurred.

Process for Determining Rider E Calibration Factor

Rider Calculated	Forecast Year-End Balance Includes	Calibration Factor Based on	Rider Effective
February	• Any actual balance from prior year • Actual losses costs and revenue for Jan • Forecast losses costs and revenue for Feb-Dec	• Forecast year-end balance • Forecast volumes for Apr-Dec • Forecast pool price for Apr-Dec	Apr 1
May	• Actual losses costs and revenue for Jan-Apr • Forecast losses costs and revenue for May-Dec	• Forecast year-end balance • Forecast volumes for Jul-Dec • Forecast pool price for Jul-Dec	Jul 1
August	• Actual losses cost and revenue for Jan-Apr • Forecast losses costs and revenue for Aug-Dec	• Forecast year-end balance • Forecast volumes for Oct-Dec • Forecast pool price for Oct-Dec	Oct 1
November	• Actual losses costs and revenue for Jan-Oct • Forecast losses costs and revenue for Nov-Dec	• Forecast year-end balance • Forecast volumes for next year • Forecast pool price for next year	Jan 1 of following year

The AESO is using a Matlab representation to calculate the Calibration Factor on a quarterly basis. The algorithms are detailed in Appendix C Technical Reports. The Matlab code and the algorithms will be tested and the process validated by an independent third party.

2.7.1 Position of Stakeholders, Calibration Factor

Position of TransCanada

TransCanada requests that the AESO consider the merits of redoing the twelve cases after a given year based on actual generation, load levels, and export and import levels. These losses that are based on actual inputs would then be compared to the forecast amounts charged to customers and the difference would be refunded or charged as appropriate to each customer. This approach would eliminate material errors caused by unplanned maintenance or forced outages, material changes in import or export levels and changes in dispatch order that affect losses. Another advantage would be that these losses based on actual inputs would inform the AESO of potential improvements in your forecast model. Any differences between losses based on actual inputs applied to the twelve cases and metered losses would then be adjusted through the calibration factor.

Position of AESO

The AESO has been asked to consider the feasibility of reconciling the costs of transmission losses to actual costs based on the hourly transactions that occur over the year. This would involve the AESO determining all transactions for all 8760 hours of the year including volumes (MWhrs) for each hourly transaction, hourly pool price and individual loss factors. This data is ultimately available to the AESO and the retrospective reconciliation of the cost of losses could be determined by AESO.

The process and rules for the financial recovery associated with transmission losses is described in section 19, 20, and 21 of the Transmission Regulation. The emphasis of the regulation is the reasonable recovery of costs associated with the transmission losses of individual generating units and prospective reconciliation of loss charges as a whole.
The Transmission Regulation states in section 19 (emphasis added):

> “**(1)(a) reasonably recover the cost** of transmission line losses on the interconnected electric system by establishing and maintaining loss factors for each generating unit based on their location and their contribution, if at all, to transmission line losses;
>
> **(1)(c)** Establish a means of determining, for each location on the transmission system, loss factors and associated charges and credits, which are anticipated to result in the **reasonable recovery** of transmission line losses;
>
> **(2)(d)** The loss factor in each location must be **representative of the impact** on average system losses by each respective generating unit or group of generating units relative to load;

> **(2)(e)** The loss factor **must be one number at each location that does not vary**, except as a result of revisions referred to in clause (b) or the reapplication of loss factors under clause (a)”

In addition, section 21 of the Transmission Regulation states (emphasis added):

> **“21(1)** In accordance with the rules, loss factors may be adjusted 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.
>
> **21(2)** If the actual cost of losses is over or under recovered in one year, the over or under recovery must be **collected or refunded in the next year or subsequent years.**

The ISO Rule on transmission losses and the Calibration Factor (Rider E) of the AESO tariff are currently structured to reasonably recover the cost of transmission losses on an individual generating unit basis. The actual cost of losses is reconciled on a system basis (i.e. the Calibration Factor socializes the difference between actual and forecast costs across all generating units, imports/exports and DOS customers). The reason the AESO has chosen to socialize the cost difference on a prospective basis is:

- The regulation requires prospective reconciliation through the application of a Calibration Factor,
- Any reconciliation that becomes retrospective impacts financial transactions which have already been settled,
- Retrospective settlement is not predictable, a principle established in the development of the new loss factor methodology,
- A retrospective financial settlement based on an hourly reconciliation of costs for a year could negatively impact generating units; importers/exporters; or DOS customers that have become retired/insolvent prior to a final reconciliation. Such a reconciliation would occur in September of the following year because final metered data is not available until seven months after initial metered data, and
- Retrospectively reconciling actual hourly transactions for transmission losses by party would negate the benefit of the Calibration Factor and potentially place transmission losses back into full regulatory oversight.

The AESO does not believe that the Transmission Regulation intended the settlement of transmission losses to be financially settled on individual actual transactions. If that had been the intent of the regulation, there would not be a need for the Calibration Factor. Also the regulation would not refer to financial settlement through the Calibration Factor occurring “in the next year or subsequent years”. The AESO continues to support the use of the calibration factor and Rider E as submitted in the 2006 GTA.

2.8 Transition Proposals

Both the AESO and Milner Power provided transition proposals to the stakeholder group. The AESO's proposal was for a two year transition with a shared cost of $ 15.4 million. The Milner proposal was for a three year transition and a shared cost of $ 41.4 million. Spreadsheets detailing the transition costs and assumptions are contained in Appendix C. The Milner transition proposal was supported by ATCO and Calpine.

2.8.1 Position of Stakeholders, Transition Proposals

Position of AltaGas

AltaGas opposes a phase-in of the new loss factors. Existing loss factors were calculated 5 years ago, and are therefore based on outdated operating conditions, and it is well understood that there are many errors built into the existing factors. Propagation of known errors and reliance on obsolete data does not bring investor confidence, and AltaGas encourages the AESO to abandon the existing numbers as soon as possible.

Position of ATCO

ATCO supported Milner Power's transition proposal on the basis of rate stability.

Position of Balancing Pool

The Balancing Pool reviewed Maxims proposal to "Phase in changes" to the loss factor calculations for generators under the STS tariff and they supported Maxim's proposal. After reviewing comments from other participants the Balancing Pool concluded that a phased-in approach is both acceptable and consistent with rate design methodology.

Position of Calpine

Calpine supported Milner Power's transition proposal.

Position of ENCANA

ENCANA did not support a transition of the new loss factor methodology

Position of ENMAX

ENMAX did not support a transition of the new loss factor methodology.

Position of EPCOR

EPCOR did not support a transition of the new loss factor methodology

Position of Milner Power

Milner Power indicated that the issue of rate stability is not new to the AESO. They tabled several extracts for the AESO's 2006 GTA to demonstrate their claim.

On page 5 – "The AESO noted that the results presented in Table 4.2.2 of the GTA could be considered "pure" results of the Cost Causation Study. However the AESO noted that these results were "developed without regard for factors or criteria other than cost-causation" and that in practice such "pure" results are frequently modified to account for other factors and criteria".

On page 6 - "The AESO also proposes a second modification to the Cost Causation Study results presented in Table 4.2.1 and 4.2.2. The classification of the POD function includes 23.6% of customer-related costs. These generally represent fixed costs attributable to the existence of a point of delivery to serve a customer, and based on the Cost Causation Study would amount to a charge of about $18,000/month per point of delivery. The AESO's current rates do not include a customer charge, and the AESO considers that applying an $18,000/month charge would impose too large a change on the AESO's lower-load customers. The AESO therefore proposes to re-classify the customer-related costs identified in the study as demand-related, as an alternative to recover the fixed POD costs."

On page 8 - "AESO recommends that transmission wires costs be classified 46.6% as demand-related and 53.4% as usage-related in the 2006 DTS rate design. Beyond maintaining customer neutrality to the phasing out of STS charges, classifying the pre-2006 STS charges as usage-related recognizes other criteria that should be considered when designing rates, including impacts on customer bills, rate stability and history, orderly transition to final rate structures and levels, and potential impact of new rates or rate structures."

On pages 11 and 12 - "Ancillary services costs to the AESO can also be viewed as a function of payments to ancillary service providers, and can be classified for rate design purposes as demand-related or usage-related. The costs could then be recovered through tariffs as fixed or variable charges, in accordance with the classification of the ancillary service payments. Basing rate design for ancillary services solely on alignment with payments to ancillary services providers may not always accord with the cost classification set out in the AS Cost Study, as cost causation is only one of several rate design criteria. In particular, the AESO is proposing ancillary services rates that also consider rate stability, simplicity of understanding, and economy of billing."

Their argument is that the new loss factor methodology results in Milner Power experiencing "rate shock" and that the AESO should give consideration for a transition plan so that rate stability is maintained.

Position of NEXEN

NEXEN initially supported Milner Powers phase in proposal. However when the AESO asked stakeholders to indicate their position on the concept of a transition for the implementation of the new loss factor methodology NEXEN indicated they were not in favor of a transition.

Position of TransCanada

TransCanada did not support a transition mechanism and has serious reservations about further changes to the methodology at this point as outlined by some Participants. To that end, TransCanada has specific comments on the proposals of Milner Power and ATCO Power as noted below. Regarding the Milner Power proposal for a transition to new loss factors, TransCanada is opposed to this proposal for the following reasons:

1." The Transmission Regulation makes no provision for a transitional mechanism.
2. When loss factors were introduced in 2001 for generators, there was no transition from postage stamp losses paid by the TA to location specific losses charged to generators.
3. Generators, who have connected to the AIES since 2001, including several TransCanada generators, were charged based on the last MW in, which was typically a very high loss charge or a lower loss credit than surrounding similarly situated generators. No transition from the existing local area generators to the more onerous losses of the new generators was provided. This resulted in a materially detrimental effect on new generation investment.
4. The loss study audit found numerous problems with the current loss factor calculations. The current losses are not indicative of a fair charge for losses to generators. Continuing to retain even a portion of these losses in place only increases the inequities that have arisen from the current loss regime.
5. New generation developers in the past invested on the basis of estimates of the loss factors conducted by the TA (and now AESO), only to find that the loss factors charged to the new generator on commissioning were substantially higher than when the investment decisions were made.
6. The instability and unpredictability of losses identified in items 3, 4 and 5 above were among the key reasons for stakeholders to pursue the kind of changes that showed up in the Transmission Development Policy and Transmission Regulation. These changes address the need for long term relatively stable price signals that can be factored into investment decisions. The magnitude of changes that Milner Power complains about is the essence of the reasons for the new method. Not only should the magnitude of changes be of concern, but the inequity in the current loss factors themselves should be of concern. The current loss factors have been overcharging some generators and giving excessive credits to other generators. Rate stability arguments lose their weight when it can be shown that an existing rate is materially in error. Such circumstances call for immediate correction to minimize the amount of unfairness between customers. If one were to find out that your bank had been overcharging you interest on your mortgage, you would demand an immediate correction, even if it meant interest charges for other customers would need to rise for the bank to maintain their return on equity. There would be no case for a "phase in" to correct such an error. In fact, an astute borrower would ask that the interest from the overpayments be repaid from the time the error occurred.
7. The proposed loss factor regime set out in the Transmission Regulation has been known in principle for about a year and the specific details of the loss factor calculation have been known since the Transmission Regulation was made law in August, 2004. Attempts to change the intent of this regulation through an unsupportable change in the process are inappropriate.
8. Milner is wrong when they state that "the proposed phase-in would only apply to those generators who face increases to their loss factors in 2006" and "those who are forecast to benefit from the forecast changes in 2006 would not be subject to a phased-in change in the loss factors." Losses are a zero sum game. Any net benefits (after applying the shift factor) that are

given to generators who face increases must come from generators who benefit from the forecast changes.

9. One of the advantages of the proposed method from Teshmont is the virtual elimination of the shift factor. The volatility and size of the shift factor over the last few years has been a problem from the perspective of selling hedges and bilateral contracts for energy. Loss uncertainty has become significant even though losses themselves are reasonably stable. The Milner proposal will invoke much larger adjustments through the shift factor than the current Teshmont proposal."

Position of TransAlta

"TransAlta reviewed the "proposed transition process" suggested by Milner Power Inc. and is absolutely opposed to such a phase in, in fact, is opposed to any phase in. As a Company that believes it has been overpaying for losses the past 5 years, the phase in suggestion would continue to see TransAlta over paying for transmission losses during the phase in period. The proposal as suggested would result in an increase in the loss factors (after consideration of the calibration factor) at Sundance and Wabamun in the first year of the phase in."

AESO Position

The AESO identified several considerations during the decision making process. They are outlined as follows:

- Lack of stakeholder support was demonstrated at the May 2, 2005 Loss Factor stakeholder meeting. Notice of the meeting was broadly circulated and the AESO did not receive any correspondence from participants unable to attend the meeting.
- The AESO noted that the AEUB did not support a transition for the loss factor process change which took place at the beginning of 2001.
- Generators have had an opportunity to be aware that the loss factor methodology was going to change beginning in 2006. Considering that loss factors have been frozen for five years and that the current shift factor accounts for more than 80% of the transmission losses, one would expect the new methodology to result in significant changes to the loss factor values.
- The Transmission Regulation called for a compression envelope limiting the magnitude of both credits and charges.
- A transition would result in new generating units paying for a charge over and above their loss factor value during the period of the transition. Depending on the length and severity of the transition, these additions charges could result in being viewed as a barrier to new entrants to the Alberta market.

2.9 Outstanding Issues to the Implementation of the Proposed Load Factor Methodology

2.9.1 Generating Unit Data Change Requests

Stakeholders were requested to verify the previous year's generating unit output and to indicate any significant changes for the coming year. Please refer to the AESO letter dated July 7, 2005 below. Some stakeholders have expressed concern that any requested changes by owners of generating units should be made public including the reasons given to the AESO for the change. The reason stakeholders have given for requesting the details is their concern that individual companies may be trying to intentionally understate the output of their units thereby reducing the loss factor assigned to the unit. This issue remains unresolved because owners requesting changes have indicated their reasons for the request remain confidential for market purposes.
The AESO's position has been that issues related to gaming of the market are the purview of the AEUB and the MSA.

AESO's Letter to Owners of Generating Units

aeso ALBERTA ELECTRIC SYSTEM OPERATOR

THE POWER OF POSSIBILITY

July 7, 2005

Owners of Alberta Generation

Re: Transmission Loss Factor Data Confirmation for 2006, Spring Season, March-May

In order to enable the AESO to carry out and perform its duties and responsibilities, including correctly assessing loss factors for generation units in 2006 and forward, we require certain reliable and accurate data. Subsequent to AESO's ongoing meetings with Stakeholders on the 2006 Loss Factor initiative, AESO will be basing generator output information on historical data as per the wishes of the loss factor stakeholder group. In that regard, attached is the second file (the first file with three seasons of data was distributed on June 8 2005) containing the PPA's you hold as a "PPA Buyer" or generating units you own. Also included in the File is the capacity we have assigned to each of the foregoing generating units based on data we have.

Subject to updated data you provide on the file, we will be using the data we inserted for purposes of calculating the loss factors, pursuant to the Loss Factor Rules.

Therefore, in order to ensure complete and accurate data, the AESO requests you review and update, as necessary, the File to:

- confirm one of the following: (i) the generating units listed are held by you as a "PPA Buyer"; (ii) the generating units listed are not subject to a PPA; or (iii) neither of the foregoing apply (Please also let us know, in the case of shared ownership of an asset, who will respond to our request.),
- confirm the final three capacity values (spring season) for each generating unit are correct, or, if not, insert the correct information on the file, explain the reason for the change, and highlight any differences, and
- return the file, updated as necessary, to the undersigned within five business days (July 14 2005), signed off by an officer of your company. (An electronic signature is adequate.)

Below are the H_2 and H_3 values for the spring season to assist you in the calculation of capacity: values:

$H_2 = 50$
$H_3 = 1400$

For your information, the calculation of the capacities was completed as per the appropriate Operation Policies and Procedures and the new Loss Factor Rule (section 9.2 of the Rules, and Appendix 7 http://www.aeso.ca/files/May252005_FinalRules.pdf). The three values you are being asked to assess and confirm and/or revise at this time correspond to high, medium and low load levels of your generating units for spring. Further, if there are other inaccuracies or deficiencies in the data we send (such as proper ownership names, missing generator assets, etc), please highlight and return to us.

If the AESO does not receive the completed File from you within five business days, we will proceed with the data we have sent you. Please be advised that if it is necessary to revise loss factor calculations at a subsequent date to correspond to updated data, you may be liable for a charge or entitled to a credit.

Please contact me at 403 539 2614 if you have any questions.

Regards,

Robert Baker, P.Eng.
Operations Forecasting

2.9.2 ISO Rule 9.1 Transmission Losses, Development of GSO Unit Dispatch

Stakeholders have identified a concern on the balancing of generation and load within the 2006 loss factor models. The issue is that the loss factors for domestic generation are calculated with the flows on the inter-ties set to zero. Using these criteria which are intended to eliminate any duplication in cost of losses for the calculation of export transactions, could result in the GSO being unable to balance generating capacity with load for the Alberta grid. In some instances, generating units might not be dispatched by the GSO model when historically the unit(s) has been dispatched and in other instances the total available average unit capacity may be less than the load. However, the collective generating units' MCR capacities are able to meet system load. The AESO will review the ISO Rule to reflect the process used to achieve the required balance between generation and load in the GSO model.

2.9.3 Interpretation of the Transmission Regulation

Stakeholders questioned whether the loss factor methodology and proposed implementation processes were consistent with the Transmission Regulation. The AESO informed the Department of Energy on its interpretation of the Transmission Regulation as it applied to the Transmission Loss Factor Methodology. The Department responded to the AESO in writing. The correspondence between the Department and AESO are included as separate files; the first is a letter to Kellan Fluckiger from Dale McMaster dated May 4, 2005; the second is a letter from Kellan Fluckiger to Dale McMaster dated May 18, 2005.

2.9.4 Independent Audit of AESO's Development of Load Flow Base Cases For 2005

Stakeholders have requested the right to hire an auditor to verify the appropriateness of the algorithms and data inputs used by the AESO in the development of the 2005 Base Cases. The timing of such an audit has not been determined nor have the stakeholders selected an auditor.

2.9.5 Stakeholder Access to the Loss Factor Tool for 2006

Stakeholders have requested the AESO to provide them with the ability to directly access the Loss Factor Tool for their own use. The AESO has agreed to provide a couple of options to stakeholders for use of the Loss Factor Tool including direct access through the AESO website and provision of the tool to a third party consultant allowing stakeholders to contract with the consultant for application of the methodology for transmission loss factor calculations. The AESO will provide stakeholders with budgets and timelines for implementation of the two options by early 2006.

2.9.6 Proxy Deferral Account

TransCanada Energy has requested the AESO to provide a retrospective reconciliation of the actual cost of transmission losses by generating unit following each calendar year.

They have also requested that the AESO charge or credit each generating unit based on the reconciliation. The AESO does not support this request which currently remains unresolved.

Appendix A

Stakeholders Detailed Comments on Loss Factor Methodology and AESO Responses

1.0 Position of ATCO

"Annex: Concerns with the Proposed R-bus 50% Area Loss Factor Methodology

This discussion paper clarifies the concerns ATCO raised regarding the proposed R Bus (50% Area) loss factor methodology.

While I am familiar with transmission calculations and load flows I cannot claim expertise in the R bus methodology. In providing these observations, I'd invite others (and esp. the experts at Teshmont) to comment and correct as necessary.

Some Definitions and Opening Thoughts:

I have used the following terms:

Marginal Loss Factor (MLF): The loss factor associated with a small (marginal) increase in generation. The MLF is the gradient of the loss curve at the point under consideration.

Incremental Loss Factor (ILF): The loss factor associated with an increment of generation. The increment could be an offer block in the merit order, the entire output of a generator or even the entire output of the generators in an area. Multiplying the ILF by the size of the increment yields a calculation of the incremental losses associated with that increment of generation."

Fig 1: Losses Associated With a Flow Across Impedance

Figure 1 shows the losses associated with a varying power flow across 0.1 p.u. (100 MVA base) impedance. The losses increase as the square of the flow and reach 10MW at 100MW of flow [Losses = I^2R].

The MLF is the slope of the losses curve which is given by the derivate with respect to I [MLF = 2IR]. At 100MW, the MLF is 20% which tells us that increasing the flow by a further 1MW would produce a 0.2MW of additional losses.

The ILF is the average MLF for the flow:

ILF = [MLF (initial) + MLF (final)] / 2

If the initial flow is 0MW (MLF (initial) = 0%), ILF = MLF (final) / 2.

For 100MW of flow, the ILF is 10% and multiplying the size of the incremental flow (100MW) by the ILF (10%) produces the losses associated by the flow (10MW).

But what if the initial flow was not 0 MW? Let us say the initial flow was 50MW (Losses = 2.5MW, MLF = 10%, ILF = 5%) and we increased the flow by an incremental 50 MW to 100MW (Losses = 10MW, MLF = 20%, ILF = 10%). The increase in losses is 10MW – 2.5 MW = 7.5MW and the ILF = 7.5 MW (inc. losses)/ 50MW (inc. flow) = 15%. We see that the ILF is the average of the initial MLF (10%) and the final MLF (20%) and is NOT simply 50% of the final MLF.
Conclusions:

ILF = [MLF (initial) + MLF (final)] / 2 and is NOT generally MLF (final) / 2 except in the special case where MLF (initial) = 0

ILF depends on the size of the increment (i.e. MLF (initial) and MLF (final) are separated by the size of the increment).

Depending on the initial flow, the MLF / 2 will either be greater or less than the ILF.

The R-Bus Method

Marginal or Incremental Loss Factors?

The R Bus method calculates the gradient of the losses curve. In other words, it calculates the MLFs at the operating points of each of the units. In concept then, it is very similar to the current marginal loss factor methodology except in that it approaches the problem by analyzing the system admittance matrix rather than by applying marginal changes to the generator outputs and solving the load flow. This results in a more accurate determination of essentially the same marginal loss factor.

Using Load as the Swing Bus

Selection of a swing bus affects the shift factor to which generators should, ideally, be insensitive. Unfortunately, after the fact corrections are difficult to recover through the market and thus methodologies which reduce the magnitude and/or variability of retroactive losses charges are beneficial. Moving the swing bus or changing to a distributed swing bus can assist and we support using this approach but note that it is not an inherent component of the R-Bus technique and could just as easily be applied to our current methodology.

Multiplying by 50%

The only attribute one can claim for individual MLFs divided by 2 is that they're half of the MLFs. They have no physical significance. They do of course fall into one half of the range that the MLFs fall into and directionally track existing MLFs.

Some Results

Fig 2: Two bus system

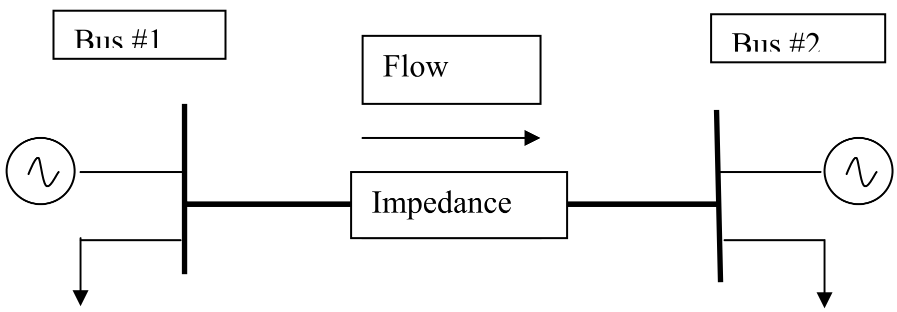


Table 1: Loss Factor Examples

Case#	Gen 1 (MW)	Load1 (MW)	Gen 2 (MW)	Load2 (MW)	Imp. (p.u.)	Flow (MW)	Losses (MW)	RBus(50%Area)		MLF/2		ILF*	
								LF1(%)	LF2(%)	LF1(%)	LF2(%)	LF1(%)	LF2(%)
1	10,000	10,000	100	100	0.01	0	0.00	0.0	0.05	0.0	0.0	0.0	-0.5
2	10,000	10,000	100	100	0.02	0	0.00	0.0	0.1	0.0	0.0	0.01	-0.99
3	10,050	10,000	50	100	0.01	50	0.25	0.0	-0.44	0.0	-0.5	0.01	-1.49
4	150	100	50	100	0.01	50	0.25	0.25	-0.25	0.25	-0.25	0.75	-0.75
5	10,000	10,025	50	25	0.01	-50	0.0625	0.0	0.3	0.0	0.25	0.0	0.0

*ILF calculated for 50MW increment

Discussion

Case 1 is intended to be a simple representation of the AIES lumped as a single generator and load (incl. losses) connected to remote 100MW load and generator. Because there is no flow over the line, there are no losses. The MLF's are zero as are the R Bus LF's. The ILFs have been calculated for a 50MW increment. The ILF at bus 2 is non-zero reflecting the fact that a 50MW generator at bus 2 saves 50MW x 0.5% = 0.25MW of losses that would otherwise arise.

Case 2 shows the same situation as Case 1 except that the line impedance has been doubled. Again, the MLF's and R bus LFs remain at zero. The ILF has doubled reflecting the increased losses savings produced by a 50 MW generator at bus 2.

Case 3 compares to Case 1 except that now only a 50MW generator exists at bus 2 and as a result, 50MW is flowing over the line, causing 0.25MW of losses. The MLF/2 and RBus LF's show about a 0.5% loss factor incentive for the generator at bus 2. Without that generator however, losses would be 1MW. The 0.75MW loss saving is reflected in the ILF (1.5% x 50MW = 0.75MW).

Case 4 is similar to Case 3 and was included to respond to the concern that using a very large bus distorted the picture. Here the flows and losses are the same. While the loss factors move as a result of the area swing bus methodology, the relative incentives are unaffected. The R Bus and MLF/s incentive remains at 0.5% whereas the ILF incentive remains at 1.5%.

Case 5 reverts to the lumped AIES approximation but this time the generator at bus #2 is larger than the local load and the flow is toward the rest of the system. The Ft. Mc Murray area may be an analogous situation. The MLF/s and RBus methods assign losses charges to the generator at bus 2. The ILF method does not. This is because without the 50MW generator, the losses the flow over the line would have been exactly the same but in the opposite direction. Accordingly, the generator at bus 2 has neither increased nor reduced losses.

Observations

RBus LF and MLF/2 reflect half of the losses that the next MW of generation would cause. The usefulness of this is not clear.
RBus LF and MLF/2 can be greater than or less than ILF.
The incentive properties of the various methods don't appear to be affected by whether a large equivalent system bus is used.
ILFs reflect the impact that an increment of generation has on the losses (but inherent to the approach is the fact that the size of the increment matters).

Objective: To examine the relative impacts of alternate loss factor methodologies on generators in differing circumstances using a simple system (attach[1].) that still facilitates intuitive understanding but is nevertheless more representative of the real system than a simple two bus model.

---

[1] It is well known that Rimbey is the epicenter of load in Alberta.

Test Procedure

ATCO proposes that the AESO:
Calculate Marginal Loss Factors for each of the generators using both the load flow and the R-Bus methods.
Scale system load as the “swing”
Use constant power factor loads (Mvar = 50% MW).

Calculate Incremental Loss Factors for each of the generators using the following approach:
Remove the entire generator,
Scale system load as the “swing”
Use constant power factor loads (Mvar = 50% MW)
ILF = change in system losses / change in generator output.

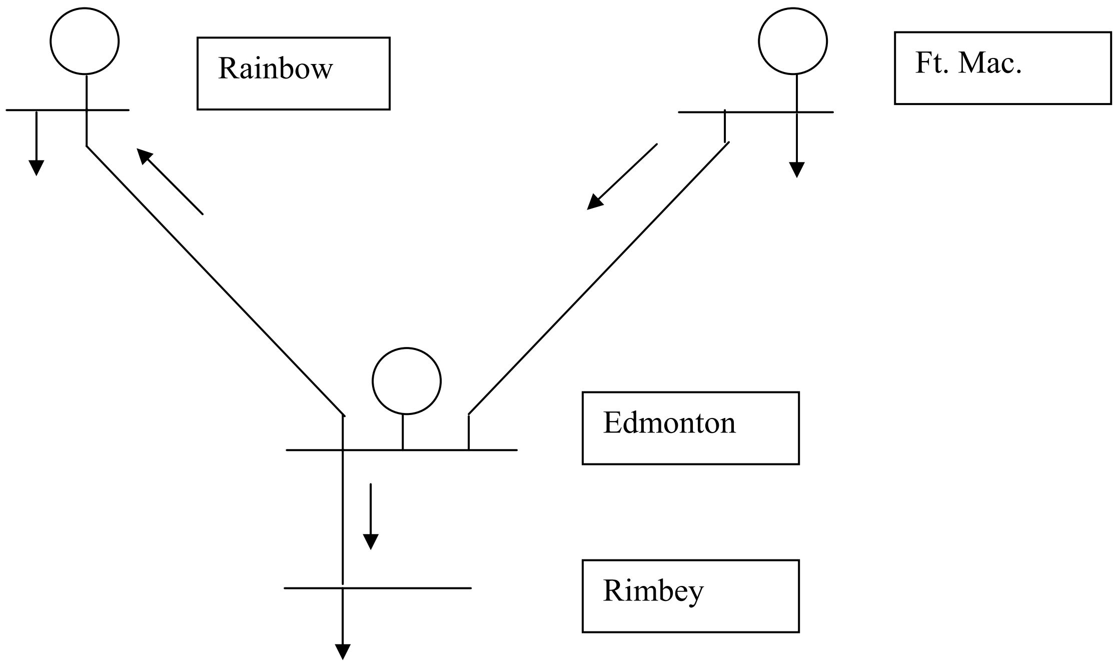
Calculate ILFs for an embedded 40MW generator at each of the generation locations (i.e. assume that three competitors each built a similar 40MW plant at the respective locations and the objective is to calculate an ILF for each of them).

Analysis

Examine relativity of MLF, MLF/2 and ILF for each of the generators.
Examine contributions of each of the generators to the total system load + losses.[2]
Examine the locational signals sent to the 40 MW generators under each methodology relative to their contributions to the total system load + losses.

[2] ILFs for the 40MW plants (when applied to the entire generation at a location) are not anticipated to sum to the total system load + losses.

Losses Test Model



Bus Data

	Gen MW	Vset (p.u.)	Load MW	Load Mvar*
Rainbow	50	1.0	100	50
Ft Mac	300	1.0	100	50
Edmonton	5214**	1.0	0	0
Rimbey	0	0	5000	2500

* = 50% of Load MW **Swing Bus in initial load flow

Line Data

From	To	R	X	B
Edmonton	Rainbow	0.21125	0.46250	0.14375
Ft. Mac	Edmonton	0.02000	0.12875	0.51000
Edmonton	Rimbey	0.00100	0.00001	0.00004

(Note: Line data was based on 144kV impedances to Rainbow and 240kV impedances to Ft. Mac. Rimbey line impedance was chosen to produce desired system losses)

Base Case Results
Bus Data

	Vmag	Vang	Gen MW	Gen Mvar
Rainbow	1.0	-17.22	50	75
Ft Mac	1.0	14.81	300	20
Edmonton	1.0	0	5214	2510
Rimbey	1.0	-1.48	0	0

Line Data

From	To	Send MW	Send Mvar	Rec MW	Rec MVAr

Edmonton	Rainbow	57	-23	50	-25
Ft. Mac	Edmonton	200	-30	193	-30
Edmonton	Rimbey	5349	2503	5000	2500

Total Losses = 364 MW = 6.5%

1.1 AESO Responses to ATCO

One of ATCO Power's criticisms of the proposed 50% area load adjustment methodology is that it does not "provide a locational signal in a manner that satisfies the regulation".

There are differences in opinions between our interpretation of locational-based generating signals and ATCO Power's interpretation. Our interpretation is that the location based signal looks only to the future and has two functions:
By providing a locational pricing signal, encourage economic siting of new generating facilities in areas which would reduce transmission losses.
Locational based signals provide a means for the AESO to charge generators for the cost of transmission losses based on their impact to system average losses.

We believe that the proposed methodology does accomplish both aspects of our interpretation of the objectives.

In the following, the numbers calculated by ATCO Power will be used as an example. It is recognized that shift factors must be applied to the tabulated loss factors to account for all losses. However, as the shift factor is applied equally to all generators and as locational based signals are differential quantities, the values tabulated are indicative of the locational-based signals sent to the generators.

In cases 3 and 4, load is greater than generation at bus 2. The differences in R bus (50% Load Area Adjustment) loss factors between the two buses (-0.44% and –0.5% respectively) would encourage generation at bus 2 rather that bus 1, reducing losses in the system.

In case 5, generation is greater than the load at bus 2. The difference in R bus (50% Area Load Adjustment) loss factors between the two buses (0.3%) would discourage additional generation at bus 2 and encourage additional generation at bus 1.

In cases 1 and 2, load and generation are balanced at bus 2. The difference in R bus (50% Area Load Adjustment) loss factors between the two buses is small (0.1%) but slightly favours additional generation at bus 1, i.e. electrically closer to the largest load.

Similar conclusions can be drawn from the ML/2 method tabulated.

We believe that the ILF methodology tabulated by ATCO does not always give correct signals according to our interpretation. In cases 3 and 4, where load exceeds generation at bus 2, the ILF differential signal (-1.5%) encourages new generation at bus 2. However in case 5, where generation exceeds load, there is no signal; we believe new generation should in fact be discouraged at bus 2. In cases 1 and 2 where the generation and load are balanced at bus 2, the signal (-0.5, and –1% respectively) encourages new generation at bus 2, when in fact new generation should be located at bus 1, closer to the larger load.

Some Results

Fig 2: Two bus system

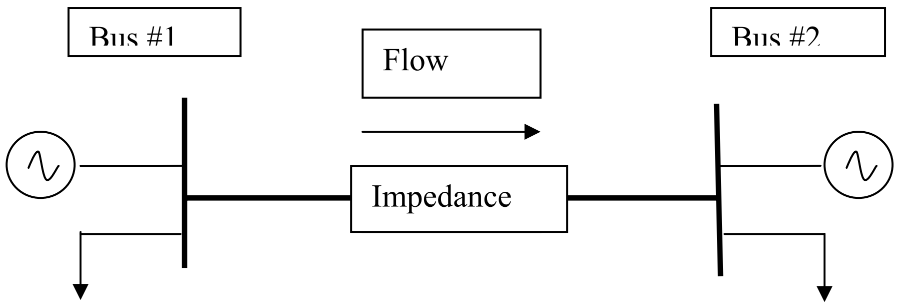


Table 1: Loss Factor Examples

Case#	Gen1 (MW)	Load1 (MW)	Gen2 (MW)	Load2 (MW)	Imp. (p.u.)	Flow (MW)	Losses (MW)	RBus(50%Area)		MLF/2		ILF*	
								LF1(%)	LF2(%)	LF1(%)	LF2(%)	LF1(%)	LF2(%
1	10,000	10,000	100	100	0.01	0	0.00	0.0	0.05	0.0	0.0	0.0	-0.5
2	10,000	10,000	100	100	0.02	0	0.00	0.0	0.1	0.0	0.0	0.01	-0.99
3	10,050	10,000	50	100	0.01	50	0.25	0.0	-0.44	0.0	-0.5	0.01	-1.49
4	150	100	50	100	0.01	50	0.25	0.25	-0.25	0.25	-0.25	0.75	-0.75
5	10,000	10,025	50	25	0.01	-50	0.0625	0.0	0.3	0.0	0.25	0.0	0.0

*ILF calculated for 50MW increment

Note: Reproduced from "ATCO Power's Comments On Transmission Loss Factor Methodology Discussion Paper (Feb 9, 2005 Draft)

We have analyzed (using the R bus methodology) a simple situation (similar to the system given by ATCO Power, where a new generator has the choice of locating at one of two ends of a transmission system, either close to a major generation/load center or close to a small remote load. This is shown by example in Figure 1. In both cases, the new generator will displace some of the existing local generation.

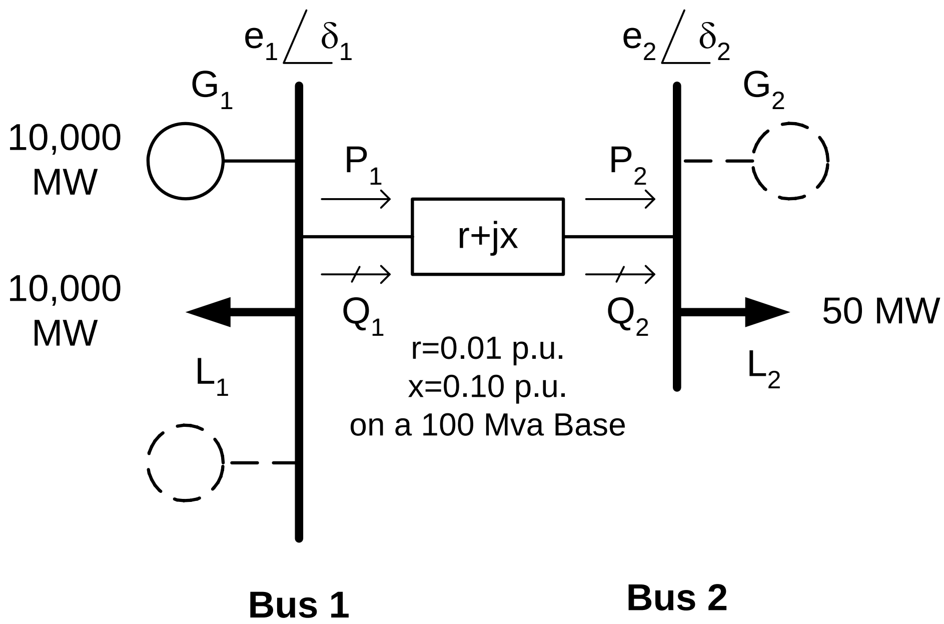


Figure 1 Simple System

Losses and loss factors have been calculated for the new generator for various capacities and for the two possible locations. In addition, the sensitivity to load factor was explored by calculating losses and loss factors for 100% load factor and generator capacity factor as well as 75% load factor (between 100% and 50% load) with 100% generator capacity factor.

The 100% load factor curves are shown in and. The 75% load factor curves are shown in and Figure 5. If the generator locates close to the major load center (Bus 1), its assigned loss factor would be the same as that of all the rest of the generators supplying the major load center. If the existing generation were sitting on top of the major load center so that no local losses are incurred, the loss factor assigned to the new generator (and all the rest of the generators) would reflect only the impact of the 50 MW load on losses. This would be only slightly greater than zero. Both the existing large generation and the new small generator would be charged for the transmission losses to the remote load, but as the load is small compared to the total generation, the loss factor assigned would be small. The loss factor shared by all generators would be 0.0051%. Thus the new generator will displace some existing generation (and hence revenues) but will pay a small charge along with all the other generators for supplying losses to the remote load.

Figure 2

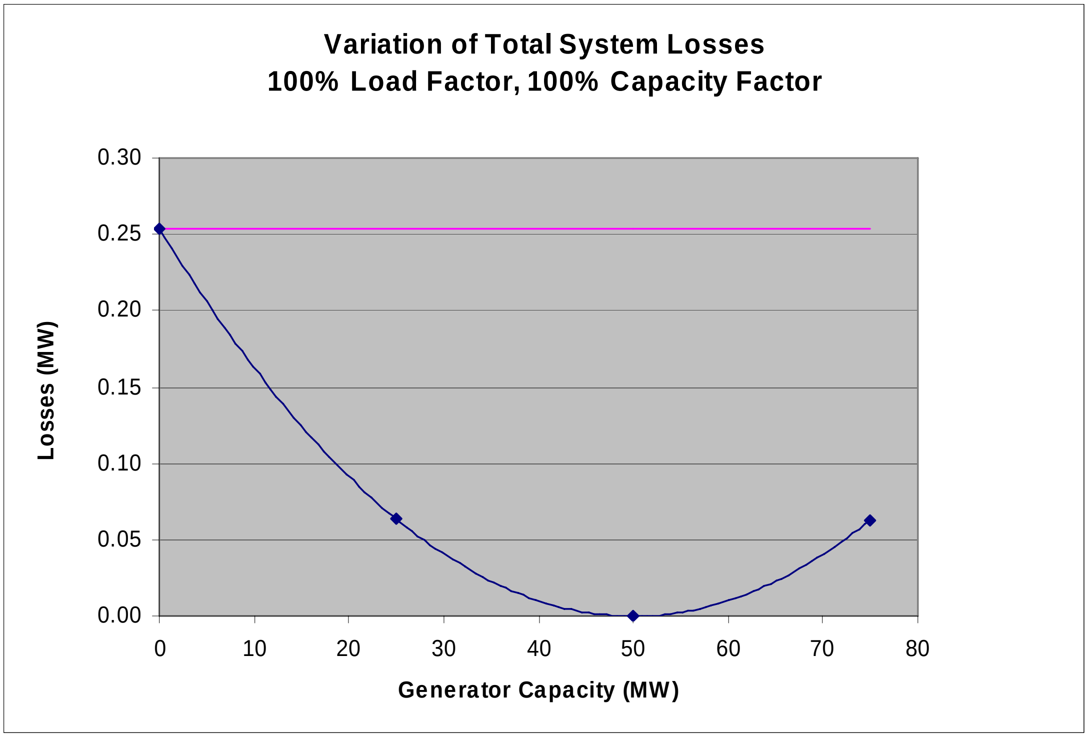


Figure 3

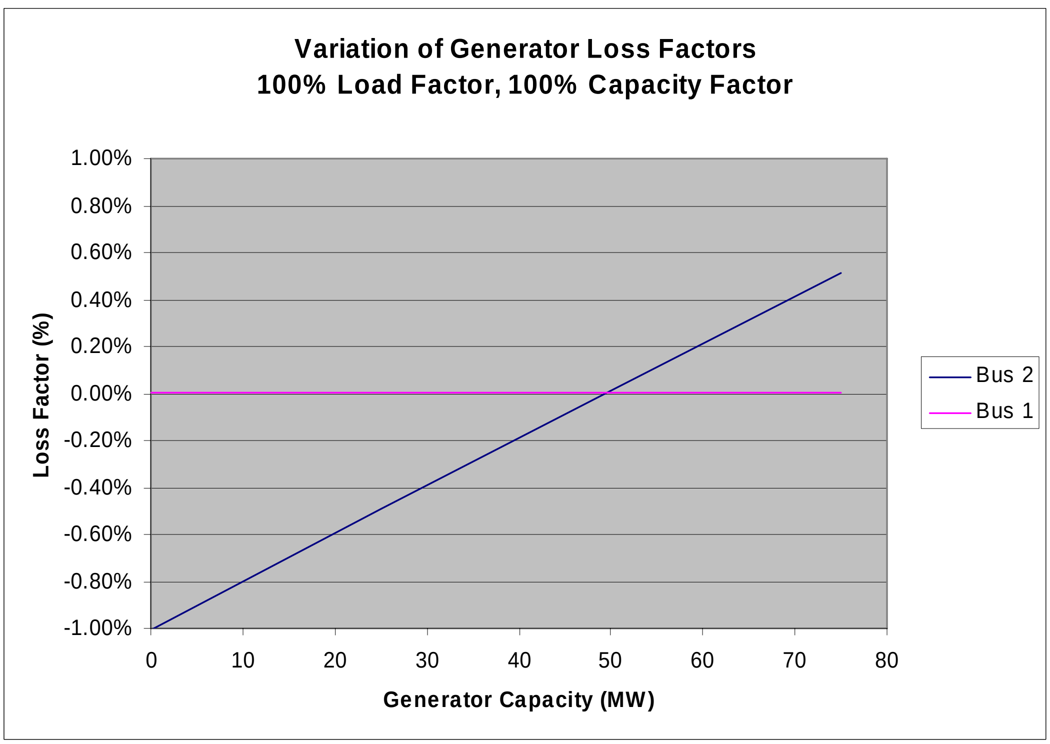


Figure 4

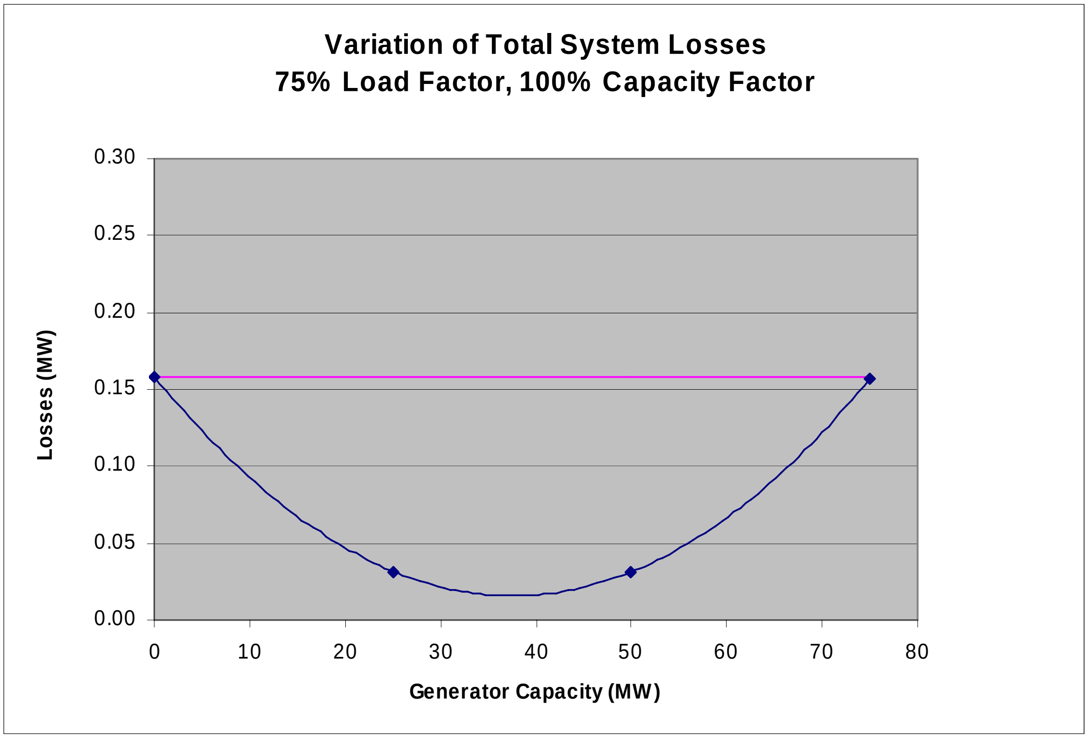
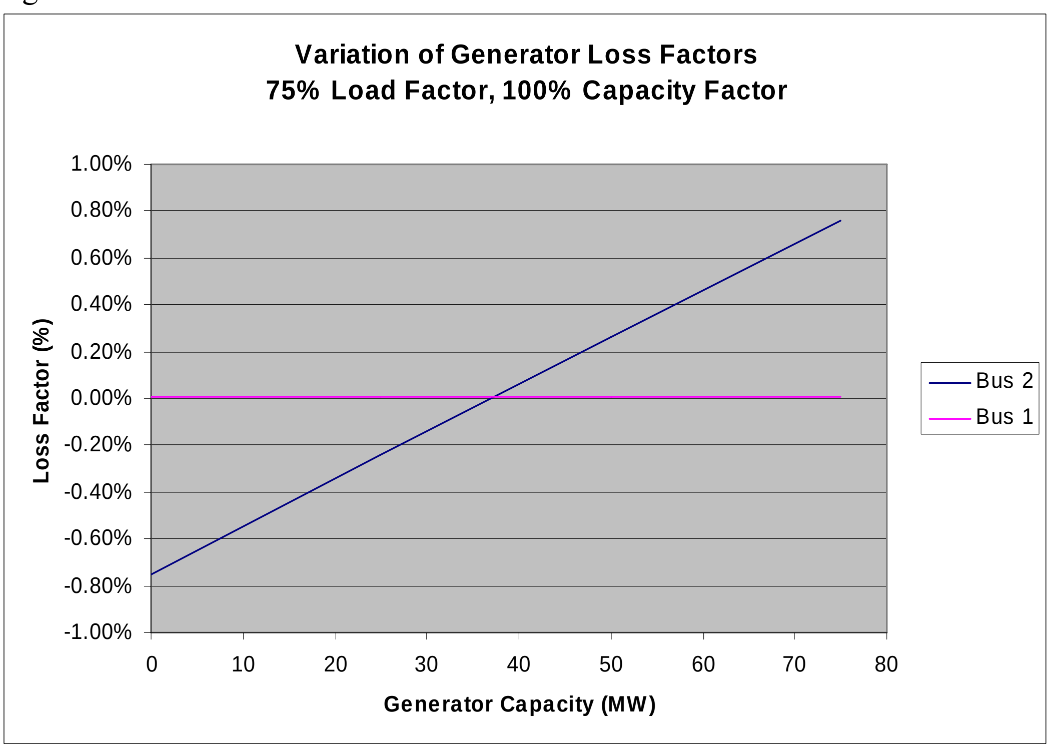

Variation of Total System Losses
75% Load Factor, 100% Capacity Factor
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Losses (MW)
0
10
20
30
40
50
60
70
80
Generator Capacity (MW)

Figure 5


Variation of Generator Loss Factors
75% Load Factor, 100% Capacity Factor
1.00%
0.80%
0.60%
0.40%
0.20%
0.00%
-0.20%
-0.40%
-0.60%
-0.80%
-1.00%
Loss Factor (%)
0
10
20
30
40
50
60
70
80
Generator Capacity (MW)
Bus 2
Bus 1

If the new generator were to locate at the new load bus and say the capacity was very small compared to the load, the losses would be reduced, but as all generators were originally being charged for losses, all generators will also share the credit for the loss reduction. The new generator would receive a large credit for the loss reduction (about 1% loss factor credit). As well, the large remote units, which are also paying for losses, must also benefit. As the new generator capacity in this case is small compared to total capacity and remote load, the net reduction in losses is small so the reduction in large generator loss factor is almost insignificant, but it does exist.

If for example the new generator were larger, say ½ the capacity of the load, (25 MW of new generation at the 50 MW load bus), the overall system losses are significantly reduced. The losses in this case would be about 25% of the original losses. The new generator would still receive a significant credit for the reduction in losses (a loss factor credit of about 0.5%), while the large generators would see a small reduction in their loss factor from .0051% to .0025%, reflecting their share in loss allocation.

If the new generation capacity matched the load, the total system loss reduction would be 100%, and on the basis of shared allocation of losses, all generators benefit and the loss reduction for all generators is a reduction in assigned loss factor from 0.0051% to zero (including the new generator located at the load bus).

If the capacity of the new generator exceeds the load, (say 75 MW compared to the 50 MW load) total system losses would start to increase as the new generation displaces some of the existing large capacity generation. In this case however, the large generators are now electrically closer to the net system load. Similar to the condition with the 25 MW unit supplying the local load (and receiving a credit), the large generators should also should receive a credit. At the same time the small generator at bus 2 should receive a loss factor charge because it is significantly contributing to the losses. For the 75 MW generating unit, the factor would increase from zero (at 50 MW capacity) to 0.51% at 75 MW The rest of the generators, also sharing in the loss distribution would see a small credit of 0.0025%, because they are now closer to the effective load on the system than the remote generator.

For a 50 MW generator at bus 2, the loss factor assigned to the new generator would be zero for this example. However, any difference between generator output and load (either surplus or deficit) would result in an increase in total losses. In a market environment where generation is dispatched according to system demand and market conditions, the output of the generator will not match the load, and losses will be incurred. Although locating the generator at the load has reduced the system losses, and should receive a credit for this, it must also be penalized for increased losses associated with any difference between output and load.

This is particularly evident in an example where the new generation capacity matches peak load, but load varies to as low as 50% of peak load, with a 75% load factor. If it is assumed that the new generator is competitive in the market and operates at 100% capacity factor, the average system losses would be about 0.032 MW and the loss factor that would be calculated for this example would be about 0.26%, reflecting increased losses because of net exports from the load bus. If the generator capacity were sized on the basis of the average load of 37.5 MW, its assigned loss factor would be close to zero. Its contribution to losses at peak load (50 MWs local load) would be about 0.02MW and also losses at 50% load (25 MWs local load) would also be about 0.02 MW. The increase in losses (which should be reflected in a charge) is counteracted by the overall reduction in average system losses, both of which are shared by all generators based on their individual contribution to the losses. The result is that the net charges to the generator would be 0.0%.

The locational-based signal for locating close to the load in the example given exists, but it is small. The main reason for this is that the all generators are required to pay for system loss increases in proportion to their capacity, and therefore must receive credits for loss reductions on the same basis. As the new generator is only a small fraction of the total generating capacity, it receives only a small fraction of the overall loss reduction benefit.

In the two-bus system, described above, if there were transmission losses associated with delivering power from 'Bus 1' to the load center, the loss factor at 'Bus 1' would be increased. The loss factors calculated for 'Bus 2' would be increased by the same amount, so the locational based signal would remain the same.

If the total generation and load at 'Bus 1' were reduced by 50%, the locational-based signal to locate at bus 2 would double.

If the new generating station has less capacity than the load, the generator receives a strong credit for locating close to the load. If the capacity of new generator is greater than the load it receives a large loss charge.

In a distributed, generation load bus environment, the proposed 50% area load adjustment methodology does provide a signal to locate such that system losses are reduced. The methodology encourages generation to be close to load centers, provided that the total generation does not exceed the load at that load centre.

2.0 Position of Calpine

Loss factor should reflect generator's impact on average system losses
While more work would be required to determine the exact impact of Calpine on average system losses, preliminary results suggest that exclusion of 250 MW of generation at Calpine will lead to increase in system losses of 39 to 42 MW. Such reduction in losses should translate to loss factor of approximately -16% (credit). Even the existing raw loss factors do not come close to reflecting this magnitude of Calpine impact on system losses. Adoption of the new methodology will further increase the gap. AESO's preliminary calculation of loss factors for 2005 shows loss factor of only -1.1% (credit) when using new methodology.
To put the significance of Calgary generation on loss saving in perspective, the IBOC generators and Calpine, when combined, produce higher MW loss savings than the proposed North South 500 kV development.

Loss factors may fail to provide location signal
Based on the AESO's methodology explanation the new methodology fails to reflect the impact generator has on the average system losses. Furthermore, in specific but realistic cases the new methodology completely fails to deliver location based signal.
The mechanism can be best explained on a simplified, yet realistic example of a remote area connected by a single 240 kV line to the bulk of the system.
In this example, the remote area has 600 MW of load and 100 MW of generation. The remote area is 500 MW deficient and this deficiency has to be supplied from the main system. System losses in this example will result from power transfer on the 240 kV line.
Based on the present loss factor methodology, the existing 100 MW generator in the remote location is receiving raw loss factor of -9.9% (credit).
Based on the proposed methodology, the existing 100 MW generator in the remote location will receive loss factor of approximately one half or –5.5% (credit).

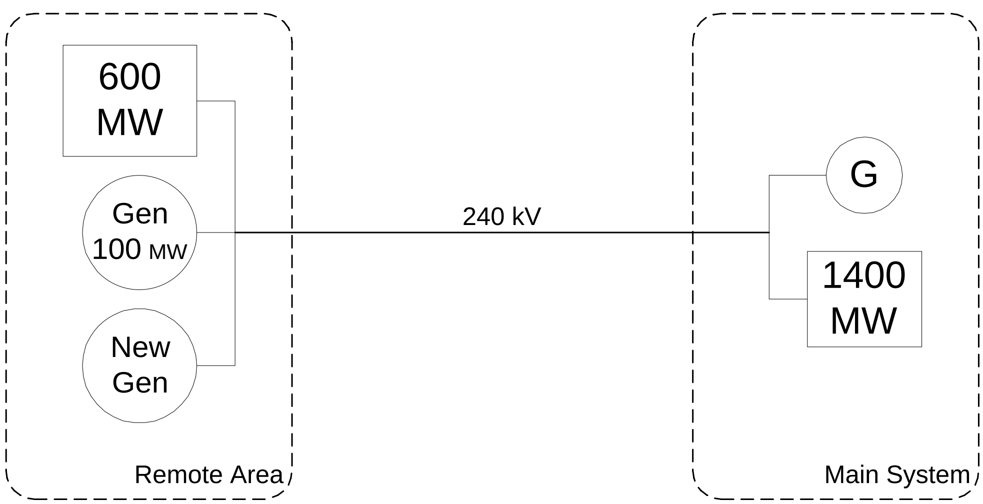


Figure 6 Example system 1

For simplicity of calculation, the example was prepared with a swing bus at the main system. The results will be conceptually also applicable when using the load modification method as proposed by the AESO. It is recognized that the adoption of load modification approach will somewhat reduce the magnitude of the impact of the concerns raised.

A new 500 MW generator locates in the remote area. Since this generator balances the flow, the losses on 240 kV transmission line are reduced to nil. The marginal loss factor at 500 MW output is 0 and the new generator receives 50% of 0 = 0 charge.

Furthermore, the loss factors for all generators will be recalculated and the loss factors of the existing generators in the remote area and the main system is reduced to nil.

The outcome of the example is:

The new generator does not receive any benefit of the average system loss reduction it had on the system. The average system loss reduction was 23.4MW or 4.7% of generator's capacity.

The benefit of the loss reduction is received by the existing generators in the main area that did not change their behavior.

The old 100 MW generator in the remote area will have loss factor reduced to 0%.

Lack of symmetry for generators receiving credit and charge

Transmission regulations stipulate that two generators having the same impact on system average losses should receive the same loss factor. It is reasonable to interpret this requirement to mean both of the following:

- two generators that increase or decrease system average losses equally should have the same loss factor and
- two generators that have the same magnitude of impact on system losses but one is increasing losses while the other is decreasing losses by the same amount should have the same absolute value of loss factor with opposite signs.

The proposed methodology will produce similar loss factors for generators having the same impact on system average losses (first point above) but will not produce the same magnitude (absolute value) of loss factors for two generators that have the same magnitude of impact on losses but one is reducing losses while the other is increasing losses. The effect of the methodology in these situations is to produce larger charges than credits as explained in the remainder of this section.

To demonstrate the "symmetry" shortcoming of the methodology, a five 200 MW units are being added to the remote area that has 500 MW of load and no generation (Figure 7).

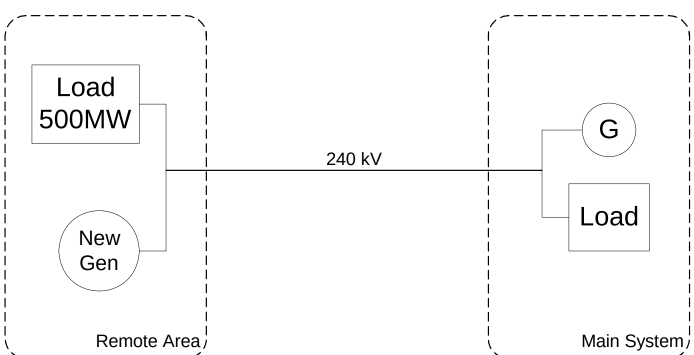


Figure 7: Symmetry example System

Figure 8 shows the system losses as a function of generation additions in the remote location. As can be seen, the impact of addition of the first unit amounts to reduction in system losses that is similar in magnitude to the magnitude of the loss increase associated with adding Unit 5; namely about 15 MW[3].

Since the impact on average losses is the same in magnitude only opposite in sign, it would be reasonable to expect similar magnitude of the loss factor, only with an opposite sign. This is not the case since, based on the new methodology, the Unit 1 will have loss factors of –2.9% while Unit 5 will have loss factor of 4.7% as apparent in Figure 9.

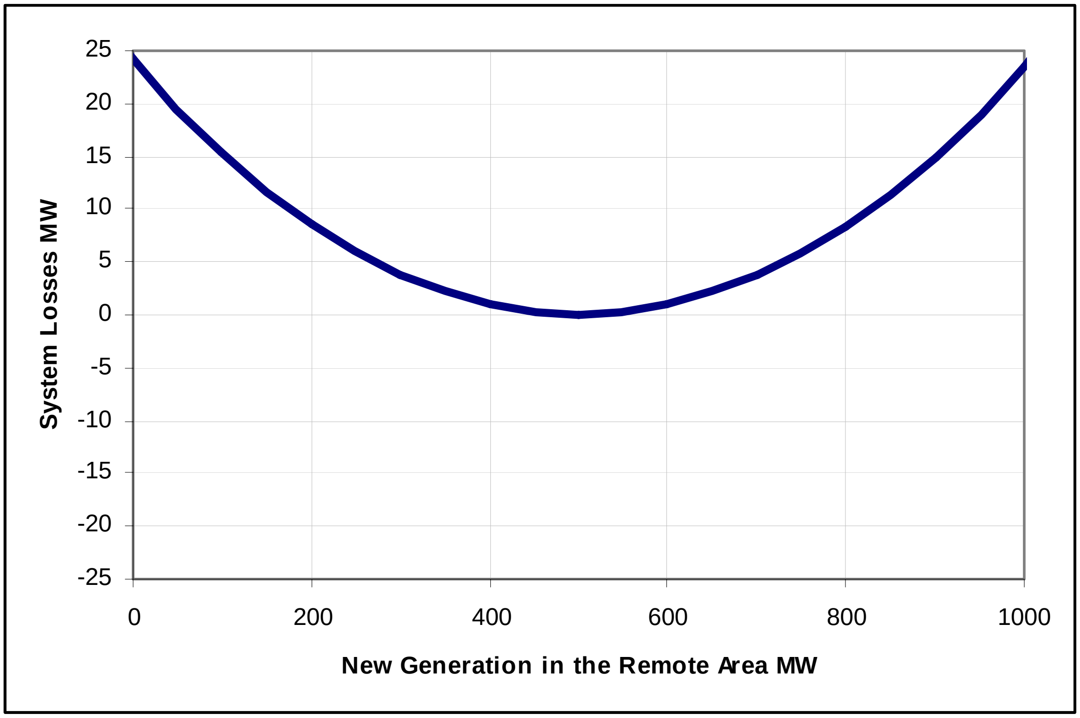


Figure 8: System Losses for Example System 1

[3] Similarly, the impact of Unit 2 and 4 will have similar magnitude of impact on losses only with the opposite sign.

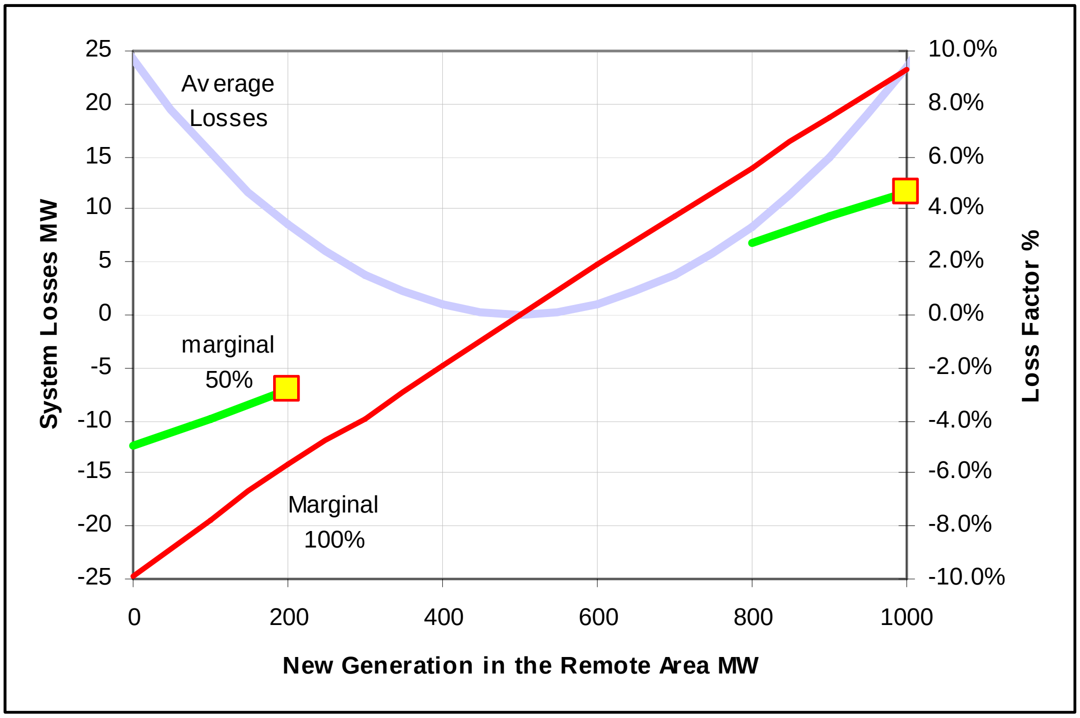


Figure 9: Marginal Loss Factor as proposed (with swing bus)

Evaluation of methodologies

Calpine shares concern first advanced by H.R. Milner with selection of criteria for valuation of loss factor methodologies.

Calpine is in particular concerned with adoption of requirement of low shift factor as the primary criteria.

It has been assumed by various parties for some time that large magnitude of shift factor indicates “inaccuracy” in the methodology itself. Such criticism fails to consider that loss factor tariff is a cost allocation mechanism. As such, it can meet its design objectives well, somewhat or not at all. The design objectives should be similar to those used when designing any tariff. The design objectives have to also reflect and comply with the applicable regulations and laws.

In the above respect, the objectives of low shift factor has little practical benefit since any methodology that produces tariff that directly recovers system average losses without adjustment would score high on the list. Example of such methodology is a postage stamp rate. Also, any methodology that uses and “internal” or hidden adjustment factor will score high. An example of the latter method is the proposed methodology that uses hidden adjustment factor of 50%.

Virtually any methodology that uses internally hidden adjustment factor can be “forced” to recover average system losses by suitable selection of the hidden factor and hence declared as shift factor free.

2.1 AESO's Response to Calpine

AESO believes that the current methodology (swing bus and marginal calculations) with very large shift factors (up to 80%) and significant variation in loss factor values (-25% to 20%) does not provide a sustainable pricing signal. Loss factors are simply too unpredictable and are subject to large changes based on additions of new generating units and the upgrading and additions of new lines. The proposed methodology which provides average losses and is limited to a three times system average envelope provides stable loss factors which can be used for longer term pricing signals. The AESO also believes that other parameters such as fuel options and heat hosts play a much bigger role in determining generating unit locations than loss factors.
Further, AESO has not agreed that loss factor determination is a tariff. The cost of losses is collected by the AESO tariff for generator access service (STS). The determination of loss factors is described in an ISO Rule and is not subject to the regulatory oversight of a tariff. The AESO is unable to reconcile the tariff arguments made in your written comments to the application of loss factors.

3.0 Milner Power's Position

ATCO has stated the proposed methodology does not fairly reflect generating unit impacts on average system losses.

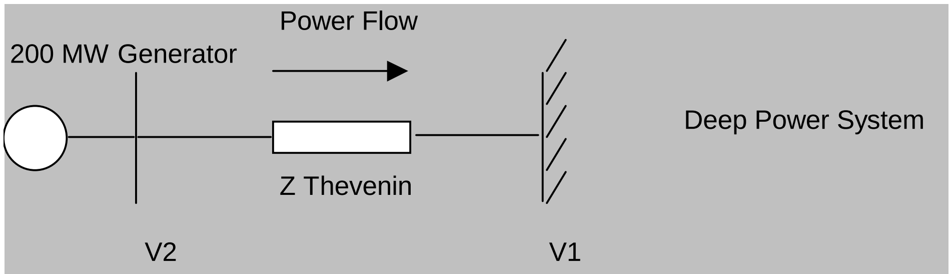
The AESO's proposed loss factor methodology evaluates the impact on system losses of the last MW of production from a generator and then divides this by two. Using this approach, the sum of all losses recovered from all generators will closely match the forecast volumes of transmission losses.

While loss factors based on the Marginal Loss Factor (MLF) of the last MW in divided by two (MLF/2) recovers the correct amount of transmission losses on an aggregate or global basis, it fails in many cases to recover the correct amounts on a generator-specific basis. The MLF/2 approach does not approximate and significantly prejudices those generators whose output creates a net reduction in system losses. As the calculation and apportionment of losses is a zero sum game, those generators most responsible for system losses are benefiting at the expense of those generators most benefiting the system through loss reduction. The following examples illustrate this. The first scenario shows the MLF/2 methodology works reasonably well. The second and third scenarios highlight the weaknesses and resulting unfairness in the MLF/2 approach.

Scenario 1
In this scenario a generator is connected to an infinite bus through a radial transmission line. This is shown in Figure 1 below. Losses of course increase with the square of the generation. Transmission losses as a function of generation in this scenario are shown in Figure 2. The marginal loss factor is simply the derivative of the losses as a function of the generation which is a straight line. The marginal loss factor as a function of generation for this scenario is shown in Figure 3.

In this scenario the average loss factor is equal to the marginal loss factor of the last MW in divided by two. In this scenario this is also equal to the average of the MLF of the first MW in and the MLF of the last MW in. This scenario approximates areas where generation greatly exceeds the area load.

In the following examples, the MLF of the last MW in is shown by the blue square. The MLF of the last MW in divided by 2 is shown by the yellow square and the average loss factor is shown by the red square.



Generator Output (MW)	**200**
Local Load (MW)	**0**
MLF	**6.31%**
MLF/2	**3.16%**
Average	**3.16%**

Figure 1: Scenario 1 Generator connected to an infinite bus through a radial transmission line.

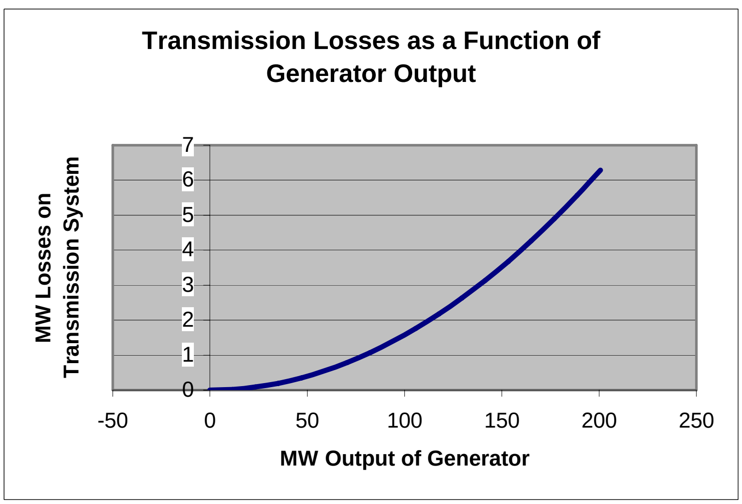


Figure 2: Scenario 1 MW losses on transmission system as a function of generator output.

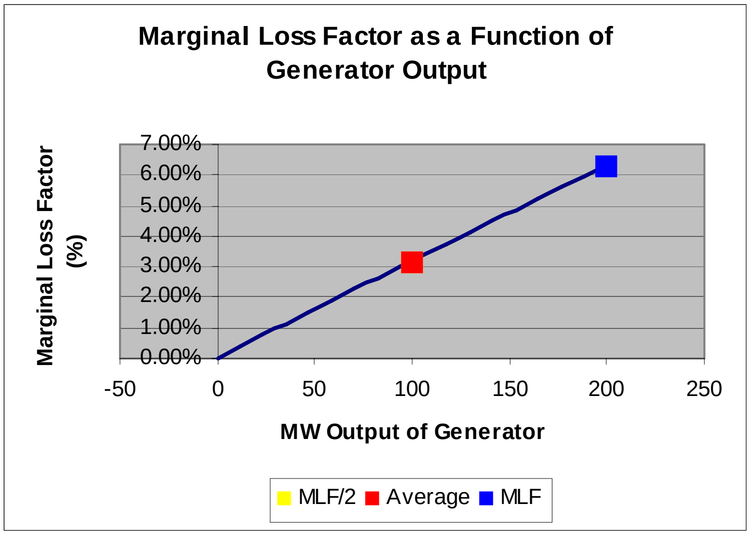
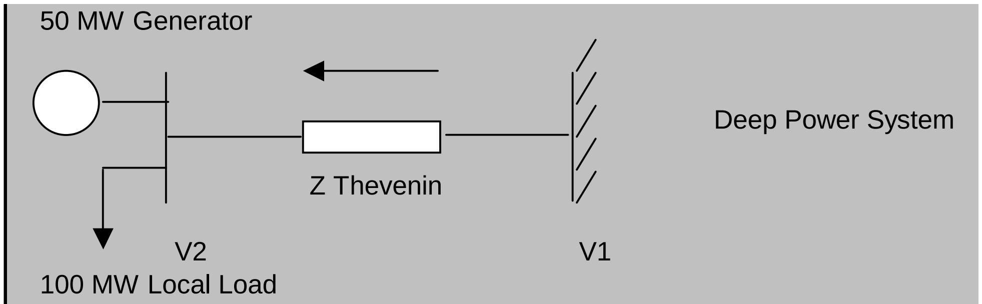


Figure 3: Scenario 1 Marginal loss factor as a function of generator output.

Scenario 2

This scenario is similar to Scenario 1 with the exception that there is a local load at the generator bus. This is shown in Figure 4. In this situation, power flows on the transmission system are dependent on the size of the local load in relation to the generation. If the generator is off line, power flows from the infinite bus over the transmission line to the load. The losses incurred are once again related to the square of the power flow on the transmission line. However, in this case when the generator is added, power flows on the transmission line will be reduced until the generation equals the local load. The transmission losses as a function of generation in this scenario are shown in Figure 5. In areas where generation is less than the local load the marginal loss factor of the last MW in remains a credit. In this scenario the average loss factor is not equal to the MLF of the last MW in divided by two. The marginal loss factor as a function of generation for this scenario is shown in Figure 6.



Generator Output (MW)	**50**
Local Load (MW)	**100**
MLF	**-1.65%**
MLF/2	**-0.83%**
Average	**-2.48%**

Figure 4: Scenario 2 Generator with local load connected to an infinite bus through a radial transmission line.

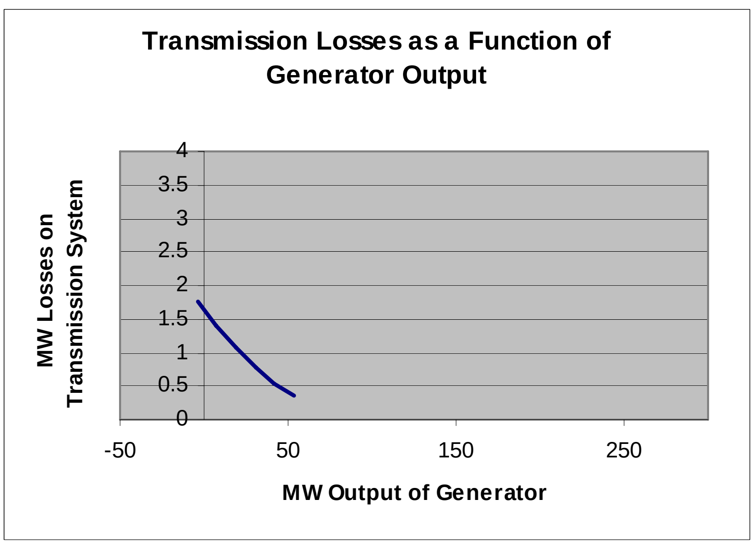


Figure 5: Scenario 2 MW losses on transmission system as a function of generator output.

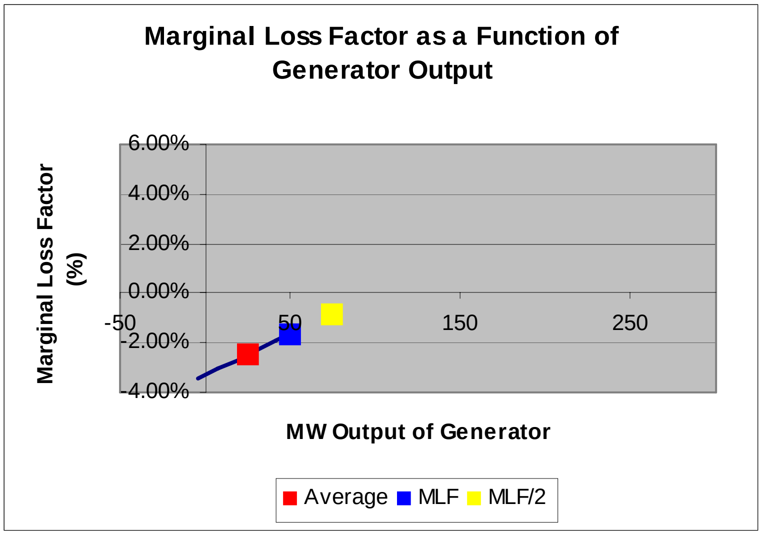
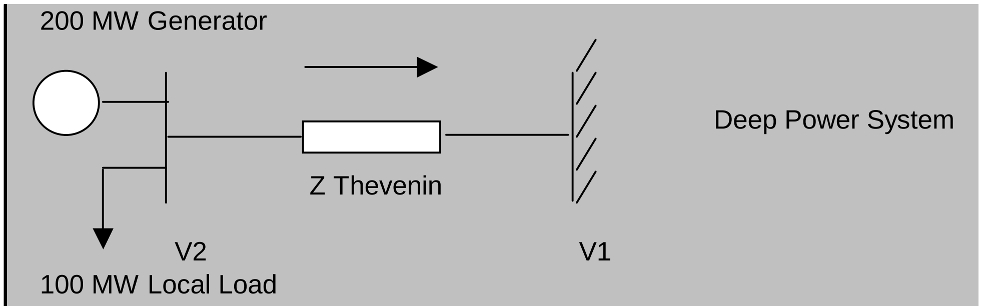


Figure 6: Scenario 2 Marginal loss factor as a function of generator output.

Scenario 3

This scenario is similar to Scenario 2. However, in this scenario the generator is approximately twice the size of the local load. This is shown in Figure 7. In this situation the MLF of the first MW in from the generator reduces system losses. The MLF of the last MW in from the generator increases system losses. Since the generator is twice the size of the local load, the amount by which the first MW in reduces system losses is exactly equal to the amount that the last MW in increases system losses. On average this generator has no impact on system losses. The transmission losses as a function of generation in this scenario are shown in Figure 8. Assessing the loss factor based on the average of the marginal loss factor of the first MW in and the marginal loss factor of the last MW in yields an average loss factor of 0%. However, dividing the marginal loss factor of the last MW in by two yields a loss factor of 1.65%; a loss factor that is not reflective of the impact on average system losses of the generator. The marginal loss factor as a function of generation for this scenario is shown in Figure 9.



Generator Output (MW)	**200**
Local Load (MW)	**100**
MLF	**3.30%**
MLF/2	**1.65%**
Average	**0.00%**

Figure 7: Scenario 3 Generator with smaller local load connected to an infinite bus through a radial transmission line.

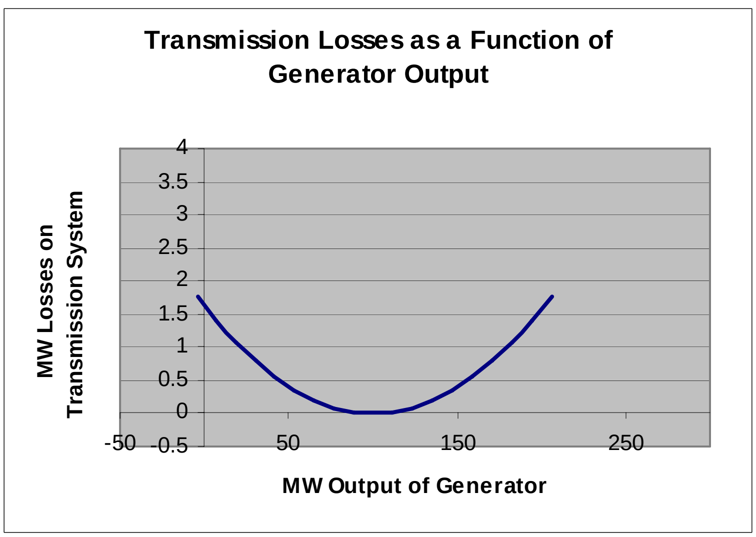


Figure 8: Scenario 3 MW losses on transmission system as a function of generator output.

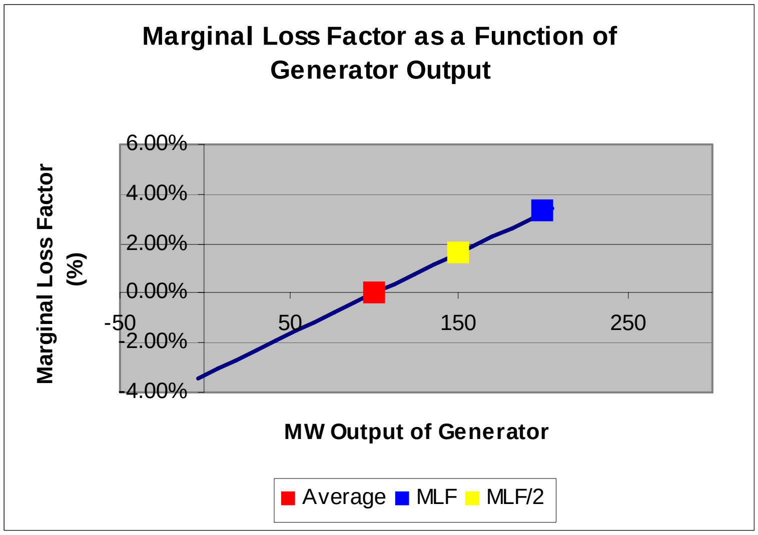


Figure 9: Scenario 3 Marginal loss factor as a function of generator output.

In each of the scenarios above, the impact on average system losses of the generator is correctly assessed by averaging the marginal loss factor of the first MW in with the marginal loss factor of the last MW in. In only one of the three scenarios is dividing the marginal loss factor of the last MW in by two, reflective of the impact on average system losses of the generator.

3.1 AESO's Response to Milner

The two-bus models shown in figures 1, 4 and 7 do not fully represent the complex interactions that occur within the AIES as a result of the regulations. No details are given regarding the 'Deep Power System'. It could consist of just a load, a combination of a generator and a load or a complex network of load and generation. If the 'Deep Power System' consists of just a load, the generator at bus 'V2' is responsible for all of the losses on the system and as indicated by the discussion in the summary on scenario 1, the proposed AESO methodology correctly assigns all of the losses to that generator. If the 'Deep Power System' of figure 1 were to consist of generation plus load, the methodology would establish a loss factor for bus V1 equal to zero and the generator at V2 would be held responsible for all of the losses. If the 'Deep Power System' however were to consist of a network with losses; all of the generators would be responsible for all of the losses within the system. The generator at V2 would therefore be responsible for not only a portion of the branch losses but also a portion of the network losses of the 'Deep Power System'. Generators in the 'Deep Power System' would be partly responsible for losses within the network but also a portion of the losses in the branch. The methodology will correctly assign more losses to the generator at V2 than generators in the 'Deep Power System' as it is further away from the load and hence is contributing more to the total system losses.

For scenario 2, in its simplest form, the 'Deep Power System' would consist of only a single generator. The proposed AESO methodology accurately accounts for all of the losses for the following variations.

If the output of the V2 generator is zero, the loss factor calculated for generator V2 would be a credit, but as its output is zero, it would receive no net benefit. The generator at V1 would be responsible for 100% of the losses.
If the output of the V2 generator were increased to 100 MW (matching the load), the loss factor at bus V2 would be zero but the calculated loss factor at bus V1 would be a charge as there would be an increase in losses to deliver its incremental output from bus V1 to Bus V2. There would be no net charges to either generator as there would be no net losses on the system.
For the condition indicated where the output of generator V2 is 50% of the load, the output of both generators would be 50MW. The loss factor for bus V1 would be a charge, less than the loss factor at its full output (condition a above) and greater than the charge at no output (condition b above). The loss factor at bus V2 would be a credit, less than the credit at no output (condition a) but greater than the credit at 100MW output. As generators at both V2 and V1 are responsible for losses, and since total losses are reduced, both generators must benefit from the total reduction in losses. The generator at bus V1 would see a net reduction in total charges from the condition a. The generator at bus V2 should see a net credit.

The proposed AESO methodology accurately distributes the benefits of loss reduction to all parties involved. This is particularly evident in scenario 3. For this scenario, if it is assumed that the generator at V2 is operating at 200 MW for 50% of the time and at zero MW for the remaining period, in the AESO methodology, 12 load flow conditions would be evaluated, 6 at 200 MW and 6 at no V2 output. At no output, the loss factor at bus V2 would be a credit. At full output the loss factor would be a charge with the same magnitude as the credit at no output. The final loss factor assigned to the generator at V2 would be the average of the loss factors for each of the load flows and would be zero (not a charge). This is exactly the average impact on system losses as stated in the summary. AESO believes that the proposed methodology does reflect the directions of the regulations.

Appendix B

ISO Rule and Appendix

ISO Rule

Transmission Planning and Enhancement

9.2 Transmission Loss Factors

9.2.1 Purpose of Rule

The purpose of this rule is to describe the means by which the ISO determines annual loss factors to provide for the reasonable cost recovery of transmission line losses in accordance with the requirements of the TR.

9.2.2 Establish and Maintain Loss Factors

.1 The ISO must establish and maintain for each calendar year loss factors in accordance with this rule.

.2 Despite rule 9.2.2.1, if the ISO determines that, in its opinion, an enhancement or upgrade to the transmission system materially affects loss factors it may adjust the loss factors in accordance with this rule 9.2.2. A material change for the purpose of this rule would be any change in loss factor to one or more generating units of 0.25%.

.3 The ISO must post on its web site and make publicly available the following:
a. A list of annual loss factors for:
- all generators directly connected to the interconnected electric system, and
- firm imports (service not currently available).

The loss factors will be posted by the first week in November prior to them becoming effective.
b. A list of loss factors for:
- demand opportunity service, and
- opportunity import and export transmission service.

The opportunity service loss factors will be posted by the first week in November prior to them becoming effective.
c. The effective date of establishment of the loss factors and the period of time they are in force pursuant to rule 9.2.2.2;
d. A list of estimated loss factors (non-binding) for the fifth year subsequent to the year referenced in the foregoing 9.2.2.3 a. for all generators directly connected to the interconnected electric system.
e. The annual generic stacking order.

.4 The ISO must follow the loss factor methodology to determine loss factors. Without restricting the foregoing, the loss factor methodology must have regard for the following:

a. Loss factors must be determined for each location on the transmission system as if no abnormal operating conditions exist;
b. The loss factor methodology should be a long-term signal and relatively stable, to allow it to be factored into investment decisions.

c. The loss factor in each location must be representative of the impact on average transmission system losses by each respective generating unit or group of generating units relative to load;
d. Loss factors must be one number at each location that does not vary, except as a result of revisions referred to in rule 9.2.2.2;
e. After determining which loss factors result in a charge or credit, every loss factor must be compressed to limit the loss factors as follows:
   (i) loss factors associated with a charge must not exceed 2 times the average transmission system loss factor, and
   (ii) loss factors associated with a credit must not exceed one times the average transmission system loss factor.

.5 The ISO must make rules with respect to the designation of loss factors in any place in Alberta where a generating unit is not located, and on request, determine a loss factor with respect to a generating unit that a person proposes to construct.

.6 A request pursuant to rule 9.2.2.5 by a market participant must be made by completing and submitting a "Preliminary Loss Factor Calculation Application" available on the ISO's website as well as paying the fee specified on the foregoing application.

.7 The ISO may not amend the loss factor methodology unless it has posted on its website not less than 3 months prior to the proposed date of amendment, a notice of its intention to do so and has sent a copy of such notice to the address specified for notices in each System Access Agreement then in force for each generating unit. An amendment to this Rule will require the ISO to undertake a formal stakeholder consultation process.

.8 An amendment to Appendix 7,"Transmission Loss Factor Methodology and Assumptions" will be treated as an amendment to this rule 9.2.

9.2.3 Recovery of Costs of Transmission Losses

.1 The ISO must establish each year with respect to each loss factor, charges or credits which if applied, would result in the recovery of the forecast costs of transmission system losses for such year.

.2 In accordance with the rules, the ISO will adjust the charges for losses with the application of 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.

.3 If the actual cost of losses is over or under recovered in one year, the over or under recovery must be collected or refunded in the next year or subsequent years.

.4 The ISO must follow the methodology set forth in the ISO's Tariff, Rider E, to determine the calibration factor.

.5 Subject to rule 9.2.4.8, the owner of a generating unit must pay the charges, and is entitled to the credits, determined by the ISO in accordance with this rule.

.6 A market participant importing electric energy under a firm service arrangement, must pay the charges, and is entitled to the credits, as determined by the ISO.

.7 A market participant receiving system access service under an interruptible service arrangement for load, import or export must pay location-based loss charges that recover the full cost of losses required to provide this service.

.8 A market participant receiving system access service for merchant transmission lines connected to the interconnected electric system, internally or intra-control area will be treated the same as the existing inter-tie lines from Alberta to Saskatchewan and British Columbia. For merchant lines not connected to the interconnected electric system (isolated), no loss factors will be accrued.

.9 The payment of charges and entitlement to credits pursuant to rules 9.2.4.7 – 9.2.4.9 inclusive, will be administered in accordance with the ISO rules.

9.2.4 Loss Factor Modeling and Assumption Details

A description of the loss factor methodology and the assumptions used to calculate loss factors are described in Appendix 7 of the ISO rules.

ALBERTA ELECTRIC SYSTEM OPERATOR

Transmission Loss Factor Methodology

And Assumptions
Appendix 7

Operations & Reliability

Final

May 5, 2005

Table of Contents

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 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 of twelve base case load flow condition. Each base-case load flow is selected to represent a typical operating condition on the transmission 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 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 peak, median and low load conditions for each season.

Each generating unit 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;
- Other generating units will be added or removed to reduce exports to zero according to the generic stacking order but recognizing any constraints imposed by the transmission system.
- Adjustments are made to historical data to correct for major maintenance outages, and major forced outages.

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 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 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 three times system average losses) 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 below:

MathCAD Implementation of Clipping with Linear Compression Algorithm

Clipping Plus Linear Compression

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

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 Plus Shift Factor

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

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 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 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.

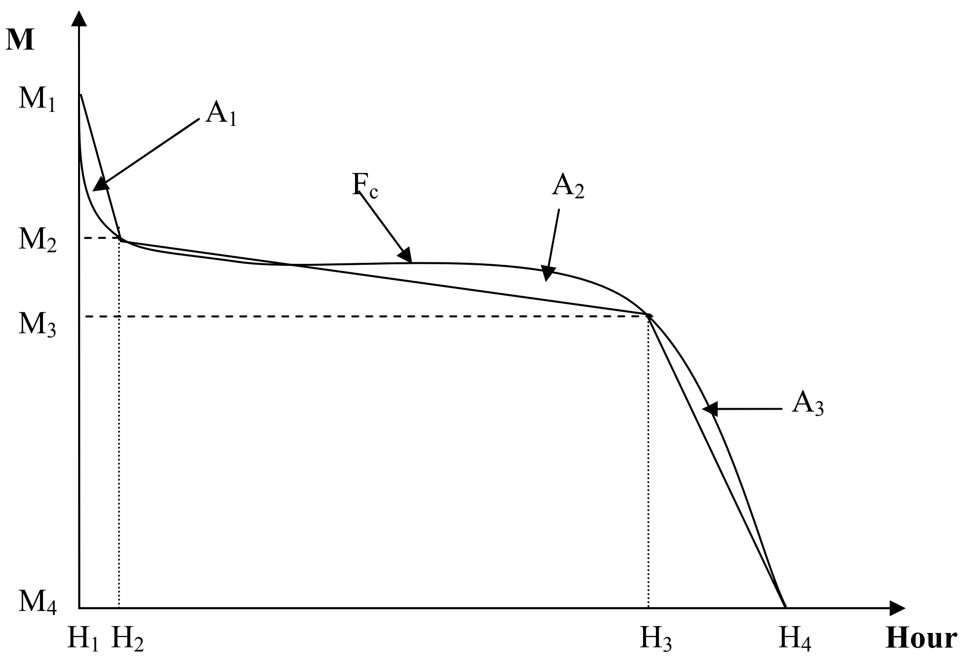


Figure 1: Graphical representation of duration curve and intermediate values.

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 for the forth coming year will include:

- All facilities that are commissioned as of December 1 of the current year and that have no Board approved plan for decommissioning prior to January 1, of the second 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.

- 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 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 and forecasted GSO for the fifth year.
- 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.

3.2 Development of Generic Stacking Order

A generic stacking order 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.
- 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 determined by the following formulas:

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

- 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.
- The ranking order for generating units will be the observed (historical) generator response.
- For price takers, the loss factor will be used to rank generating units within a subgroup. The ISO will use two blocks of energy.
- 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.

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 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 Incapability Factor where the Incapability Factor (ICBF) = 1 – Available Capacity Factor;
- 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 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. The ISO will review the base cases with owners of generating units to ensure that the data used is accurate.

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 an annual basis;
- based on the three load cases for each of the four seasons;
- 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.

Appendix C

Technical Reports for the Proposed Loss Factor Methodology

2006
Generic Stacking Order

August 18 2005

	Name	Signature	Date
Prepared by:	Ashikur Bhuiya, P.Eng.		
Approved by:	Robert Baker, P.Eng.		
Approved by:	Jerry Mossing		

APEGGA Permit to Practice P-8200

TABLE OF CONTENTS

1.0 Purpose

The purpose of this document is to describe the 2006 Generic Stacking Order.

2.0 Introduction

The Generic Stacking Order (GSO) is a key component in the loss factor calculation, operational forecasts, planning studies, and General Tariff Application process. Generators are dispatched to meet system demand in the base cases according to the order and generation amount specified in the GSO.

The GSO contains two key pieces of information –

1. Generation supply levels on a net-to-grid basis (NTG) for 12 seasonal cases[4] (four seasons and three load levels) for all generators, and
2. Generation dispatch order.

Starting in 2006, the Rule governing the determination of the GSO generation supply levels can be located at: http://www.aeso.ca/files/May252005_FinalRules.pdf. In summary, the generation supply levels are determined using historical data for existing generators (in service for more than a year). For generators that have been in service for less than one year, the supply levels are estimated by the Incapability Factors. To determine dispatch order, a statistical analysis is used to determine a relationship between the generator output and the actual historical hourly pool price. The process is explained in 'Key Changes'. AESO will request annually from generation owners confirmation that the previous year's historical data is appropriate to use. Additional blocks are used where necessary to reflect generators' multiple bidding strategies.

The TMR requirement (please refer to http://www.aeso.ca/files/ISO_OPP_2005_05_25.pdf for details) supersedes all other operational criteria and hence TMR generators are dispatched first on the list when required to fulfill the reliability criteria.

3.0 Background

In 2006, the AESO will use a new methodology, 50% Area Load Corrected R-Matrix, for the determination of generator loss factors. The new methodology reflects the requirements of the

[4] Loss Factor base cases are relevant to NTG amount whereas operations and planning security base cases use more detailed modeling of the system including the behind the fence elements.

Alberta Department Of Energy (DOE) 2004 Transmission Regulation. The regulation indicates that loss factors must be calculated from the average impact of generators on the Alberta Interconnected Electrical System (AIES). The regulation directed the AESO to implement a new methodology to meet these requirements. The AESO has consulted with stakeholders in the development of the new loss factor methodology including the development of new rules for the preparation of the GSO.

Previous GSO's used generators STS contract levels as capacity amounts. Moving to a historical generation basis has several advantages, including;

- Representative of actual generator energy market dispatch for the previous period
- Addresses the issue of confidentiality of maintenance data by including actual maintenance and forced outages from the previous period
- Reduces necessity for the AESO to forecast generator / pool price relationships

4.0 2006 GSO Key Changes

The major differences between previous GSOs and the 2006 GSO are;

1. Average historical net-to-grid (NTG) output of a generator is considered for each seasonal case.
2. Generator owners are provided an opportunity to comment and suggest revisions to the GSO capacities to reflect an intent change operation in a future year.
3. The hours used for averaging the historical generator output are taken from the AIES seasonal load duration curve analysis (Please see Appendix-A of AESO Loss Factor Rules).
4. No maintenance or outage data is used in the 2006 GSO as average historical net-to-grid output of a generator inherently contains this information.
5. 12 seasonal net-to-grid generations are assigned to each individual generator at the point of supply (POS).

6. The order except for units such as wind and hydro generation, is determined by the actual price responses of the generators in each group.

7. New generators that are expected to be connected in the forecast year will be included in the GSO. These are generators with signed contracts to connect or who have made significant financial commitments to connect. Generators who have filed decommissioning plans with the AESO will be removed accordingly.

   AESO relies on the Canadian Electricity Association (CEA) information in the event of new generators or in the case of a lack of updated information from the generators on their availability. The incapability Factors (ICBF) is used to calculate the power available to the AIES. (1- ICBF) has been considered as equivalent to Available Capacity Factors (ACF). The ICBFs are obtained from CEA's latest annual report on Generation Equipment Status.

8. The 2006 GSO considers the NTG amount at the point of supply (POS). Since any given loss factor is primarily the function of net to grid amount of generation, the 2006 GSO represents an aggregate of generation at the point of supply. An equivalent generator is considered at the bus from which the NTG amount related to the Measurement Point Identification (MPID) is obtained. For example, Horseshoe has 4 generators with a single MPID which is HSH. The 4 generators are connected to Bus 172 (12 kV). They are represented as a single unit at Bus 171 (138 kV) because the AESO billing database contains NTG data for all of these four units (related to MPID HSH) at Bus 171. The same approach is applied to the Industrial System Designations (ISD). All ISDs are represented by a single equivalent generator and load. The GSO contains a column with bus numbers for corresponding MPIDs.

9. An energy stacking order is created based on nine months of each generators historical price response. The generation energy market behavior analysis is updated with the latest historical data from the period June 1 2004 to February 28 2005. Each generator's hourly output capacity and corresponding hourly pool price are plotted and separated into equal price intervals. Then, a statistical analysis is applied to the intervals to analyze the changes between intervals. A

threshold is set to determine if the change between intervals is significant. A significant change is defined as a new block. The threshold is defined as a percentage of the generating unit's MCR that results in five blocks or less. In order to avoid additional complexity for limited modeling improvement, at most two blocks are considered in the energy stacking order and reflected in the GSO. However, not all generators have a 2nd block. The statistical analysis shows that some generators have an insignificant amount of generation in the 2nd block which indicates their price insensitivity.

The price response analysis used to construct the GSO is consistent with the losses forecast as filed with the AESO's General Tariff Application.

The 2006 GSO is similar to its predecessors in the following aspects:

1. The wind and hydro units are ranked according to their relative loss factors.
2. No bid price, specific TMR, maintenance schedules, or heat rate information is revealed.
3. Multiple blocks (two blocks) are used to represent the historical response of the generators to pool price.
4. STS contract and incapability factors (ICBF) is used to determine the amount of predicted generation level for new generators.

5.0 2006 Generic Stacking Order

The following describes the application of the GSO to the loss factor base cases:

1) Transmission Must Run (TMR) generators – the generators represent the expected TMR dispatch (of gas, combined cycle, or other units) beyond area generation energy market participation. The TMR units are listed in the AESO OPPs 501 and 510. TMR is required in specific areas of the AIES to meet reliability criteria The total net-to-grid (NTG) amount assigned to the TMR generators in the 2006 GSO is obtained from the following two sources:

   a) The average historical net-to-grid (NTG) is calculated for 12 seasonal cases in the past twelve months (June 1 2004 to May 31 2005). The AIES seasonal load duration curve analysis is used to obtain the NTG amount of each generator.

b) The minimum TMR requirement is obtained using OPPs 501 and 510.

According to the OPPs when the area criteria requirement is not met by the generation from local generators through energy market dispatches, TMR dispatches will be issued to TMR-contracted generators to make up the shortfall. TMR-contracted generators will be dispatched according to the TMR dispatch orders. The actual TMR dispatch order is confidential to the AESO.

Area load is required to determine the minimum TMR requirement for any TMR area such as North-West area. The minimum TMR requirement is function of local area load. The area load forecast is applied for high, medium and low seasonal cases. Using the historical hourly area load levels and using the regression analysis as explained in Appendix-A of the AESO Rule on Loss Factors, a minimum TMR generation requirement is assigned to generators listed in the OPPs according to these seasonal load levels. The historical TMR level as calculated in Appendix A is adjusted as per the relevant OPP if necessary to meet the minimum reliability requirements.

2) Most of the data used in 2006 GSO such as Alberta system load, hourly pool price and generation amount at each POS are historical and taken from the most recent 12 months' data found in the AESO's billing system. The data extraction period is June 1 2004 to May 31 2005.

3) In general, the energy stacking order is formed to more closely reflect an actual operational perspective. The generators may bid multiple blocks but the typical block size beyond the 2nd block is very small

4) Wind Generation – Wind generation does not have a relationship to pool price.

5) Small Power Research & Development – The relative order remains the same as the 2005 GSO. SPR&D generators are exempt by law from paying for losses.

6) Distribution Connected Generation – consists of distribution connected generators with STS contracts who occasionally supplies power to the AIES. Several prime movers may exist at a distribution generation location. The placement of the distribution generation in the stacking order is determined mainly by the predominant source of generation at the STS location and ranked by historical hourly pool price.

7) Preliminary Generation – consists of the generators with preliminary status. These generators do not have a contract with the AESO but are included in the 2006 GSO as it is expected they will connect.

Curve Analysis

Application to the AIES Load Duration and Generator Output Profile

ALBERTA ELECTRIC SYSTEM OPERATOR

April 06, 2005

Determination of High, Median and Low Scenarios

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.

Proposal: AESO and Teshmont worked in parallel and came up with similar proposal for obtaining the intermediate values. Figure 1 shows the concept of the proposal 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 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.

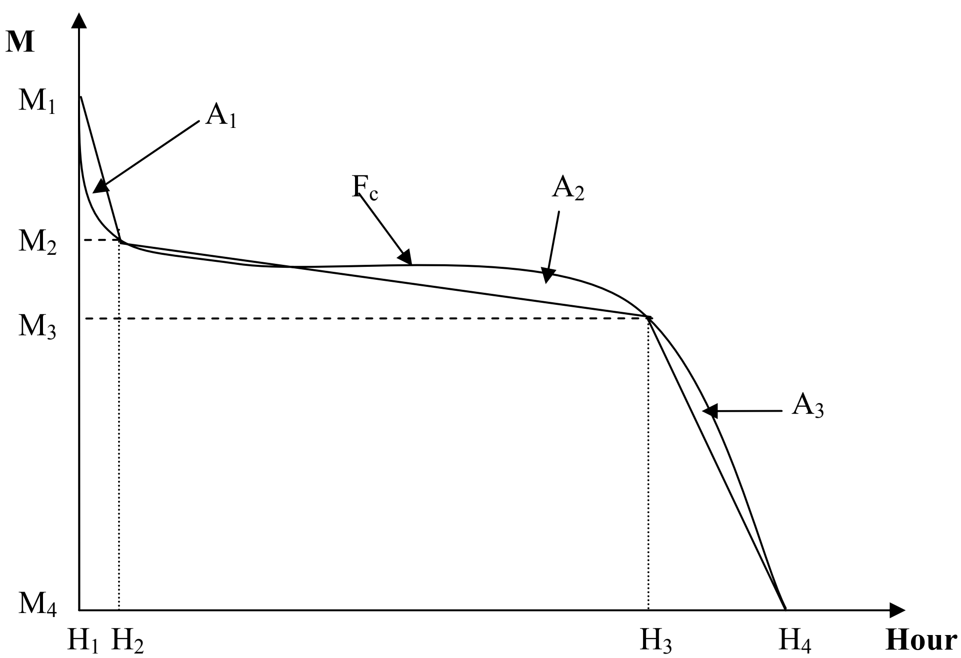


Figure 1: Graphical representation of AESO proposal.

The next 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 given below and mathematical details are not provided here.

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

    Minimize ($A_1^2 + A_2^2 + A_3^2$).
11. 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.
12. 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

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

Result: A MATLAB program was written to test the methodology proposed here and the program was tested on numbers of different Load Duration Curves and Generation

Supply Curves. The program operates quickly (i.e. obtaining results is not laborious) with a step size of 25 Hours.

Load Duration Curves: Load Duration Curves for 4 seasons of years 2002, 2003 and 2004 are used for analysis and the results are summarized below.

Table 1: Summary of Load Duration Curve analysis for 2002.

Year : 2002						
Season	**Scenario**	**End Hour**	**MW**	**Percentile**	**Duration (Hr)**	**Average MW**
Winter		1	7934	100		
	High	50	7576	97.7	50	7693
	Medium	2100	5807	2.8	2050	6696
	Low	2160	5648	0	60	5738
Spring		1	7589	100		
	High	50	7289	97.8	50	7380
	Medium	2050	5654	7.2	2000	6472
	Low	2207	5326	0	157	5556
Summer		1	8217	100		
	High	50	7977	97.8	50	8070
	Medium	2100	5734	4.9	2050	6848
	Low	2208	5309	0	108	5547
Fall		1	8326	100		
	High	50	7908	97.8	50	8023
	Medium	1850	6346	15.4	1800	7128
	Low	2185	5857	0	335	6140

Table 2: Summary of Load Duration Curve analysis for 2003.

Year : 2003						
Season	**Scenario**	**End Hour**	**MW**	**Percentile**	**Duration (Hr)**	**Average MW**
Winter		1	8570	100		
	High	50	8238	97.7	50	8362
	Medium	1950	6617	9.8	1900	7455
	Low	2160	6241	0	210	6495
Spring		1	8222	100		
	High	50	7868	97.8	50	7967
	Medium	2100	6135	4.9	2050	6998
	Low	2207	5855	0	107	6053
Summer		1	8295	100		
	High	50	8057	97.8	50	8139
	Medium	2150	5973	2.7	2100	7011
	Low	2208	5658	0	58	5886

Fall		1	8578	100		
	High	50	8174	97.8	50	8301
	Medium	2050	6313	6.2	2000	7240
	Low	2185	6007	0	135	6214

Table 3: Summary of Load Duration Curve analysis for 2004.

Year : 2004						
Season	**Scenario**	**End Hour**	**MW**	**Percentile**	**Duration (Hr)**	**Average MW**
Winter		1	8967	100		
	High	50	8586	97.8	50	8682
	Medium	2150	6725	1.6	2100	7659
	Low	2184	6557	0	34	6675
Spring		1	8358	100		
	High	50	8006	97.8	50	8093
	Medium	1850	6579	16.2	1800	7297
	Low	2207	6094	0	357	6395
Summer		1	8578	100		
	High	150	8225	93.3	150	8344
	Medium	2100	6455	4.9	1950	7341
	Low	2208	6017	0	108	6356
Fall		1	8700	100		
	High	50	8304	97.8	50	8437
	Medium	1400	7247	36.0	1350	7766
	Low	2185	6367	0	785	6804

Generation Supply Curves: 6 generators of 5 different types are chosen and results are below. Table 4 provides summary when all zero generation hours are considered and Table 5 represents summary when only non-zero generation hours are considered.

Table 4: High, Medium and Low scenarios for different types of generators.

Generation (zero generation hours are included)						
Type	**Scenario**	**End Hour**	**MW**	**Percentile**	**Duration (Hr)**	**Average MW**
Coal		1	409	100		
	High	1450	386	33.7	1450	397
	Medium	1850	334	15.4	400	369
	Low	2185	0	0	335	168
Co-Gen mk		1	188	100		
	High	50	167	97.8	50	168
	Medium	1000	157	54.3	950	161
	Low	2185	0	0	1185	78
Co-Gen		1	253	100		
	High	900	208	58.9	900	222

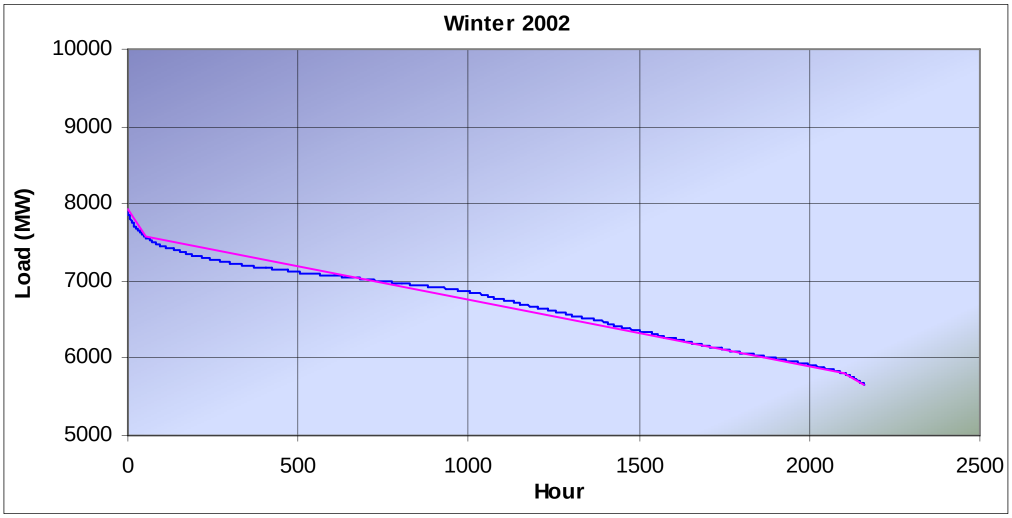
	Medium	2050	152	6.2	1150	186
	Low	2185	0	0	135	109
Hydro		1	252	100		
	High	50	175	97.8	50	189
	Medium	650	55	70.3	600	109
	Low	2185	0	0	1535	25
Wind		1	73	100		
	High	200	72	90.9	200	73
	Medium	1650	1	24.5	1450	36
	Low	2185	0	0	535	0
Gas		1	41	100		
	High	75	0	96.6	75	20
	Medium	2185	0	0	2110	0
	Low	2185	0	0	0	-

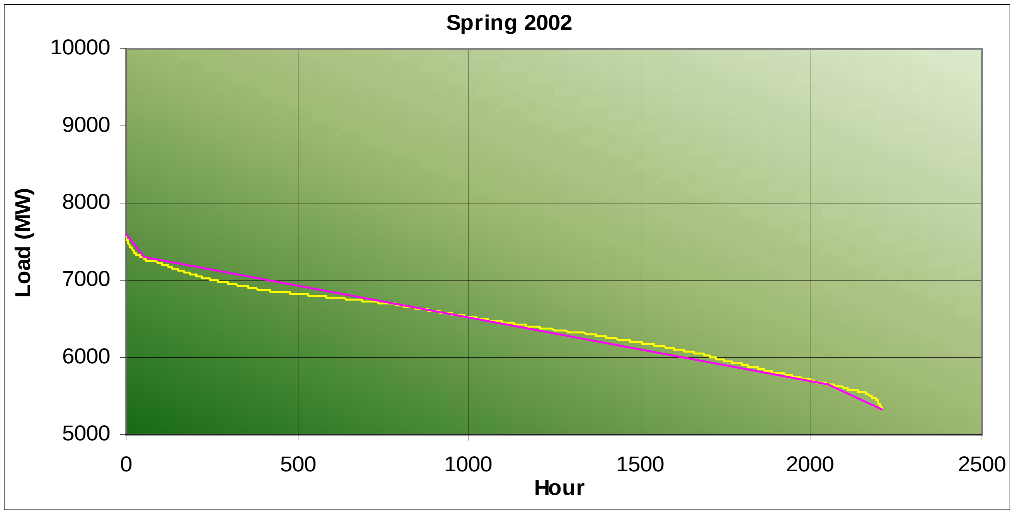
Table 5: High, Medium and Low scenarios for different types of generators.

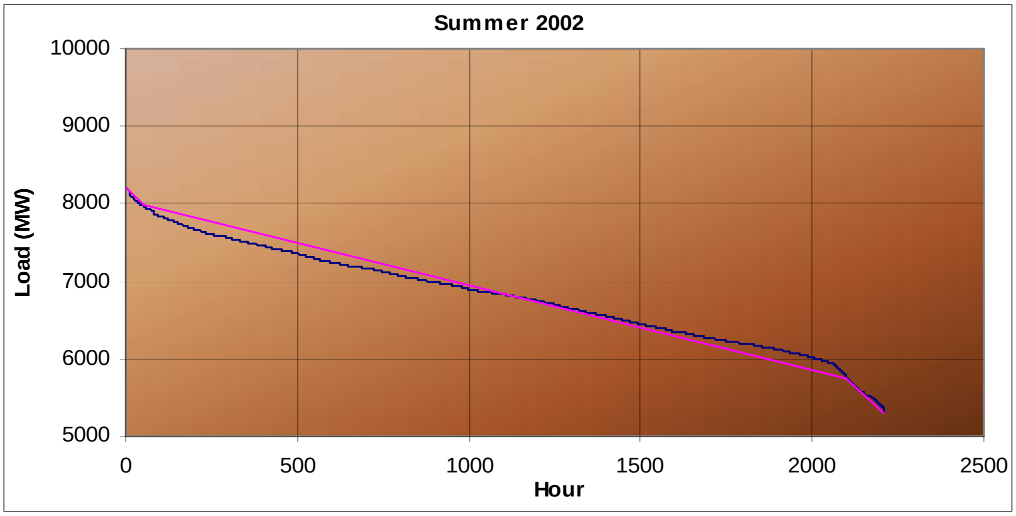
Generation (zero generation hours are excluded)						
Type	**Scenario**	**End Hour**	**MW**	**Percentile**	**Duration (Hr)**	**Average MW**
Coal		1	409	100		
	High	1600	376	26.8	1600	396
	Medium	1950	280	10.8	350	345
	Low	2075	0	5.1	125	207
Co-Gen 1		1	188	100		
	High	50	167	97.8	50	168
	Medium	1550	145	29.1	1500	158
	Low	1620	0	25.9	70	121
Co-Gen 2		1	253	100		
	High	900	208	58.9	900	222
	Medium	2050	152	6.2	1150	186
	Low	2183	0	0.1	133	111
Hydro		1	252	100		
	High	50	175	97.8	50	189
	Medium	500	88	77.2	450	124
	Low	1596	0	27.0	1096	44
Wind		1	73	100		
	High	200	72	90.9	200	73
	Medium	1650	1	24.5	1450	36
	Low	1753	0	19.8	103	0
Gas		1	41	100		
	High	10	41	99.6	10	41
	Medium	60	2	97.3	50	21
	Low	75	0	96.6	15	0

Appendix –A

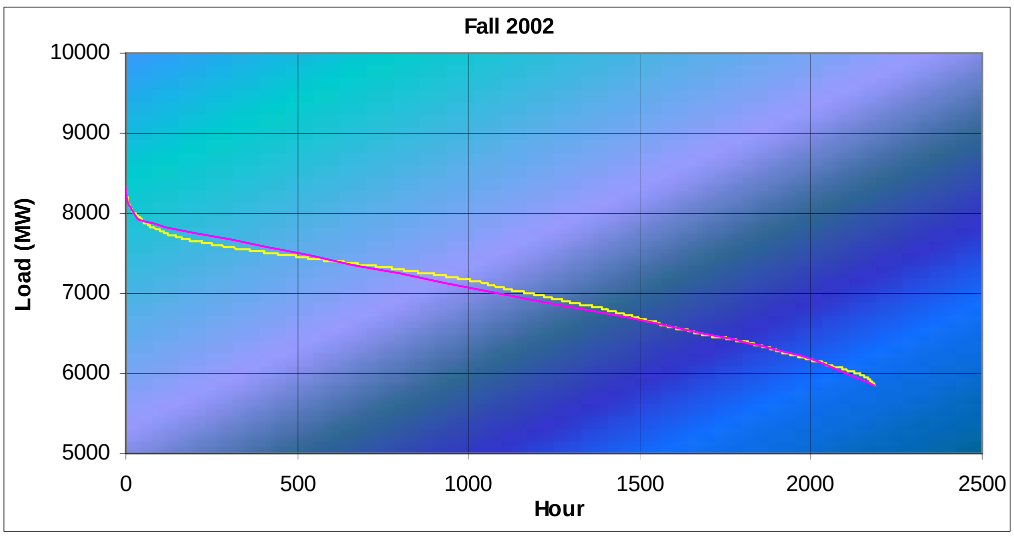
Load Duration Curves



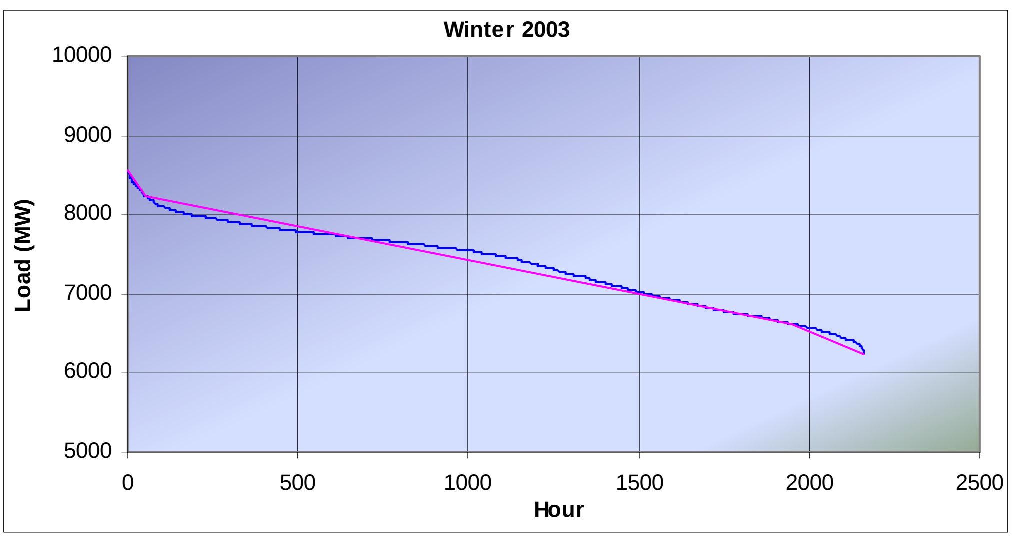




Summer 2002
Load (MW)
10000
9000
8000
7000
6000
5000
0
500
1000
1500
2000
2500
Hour

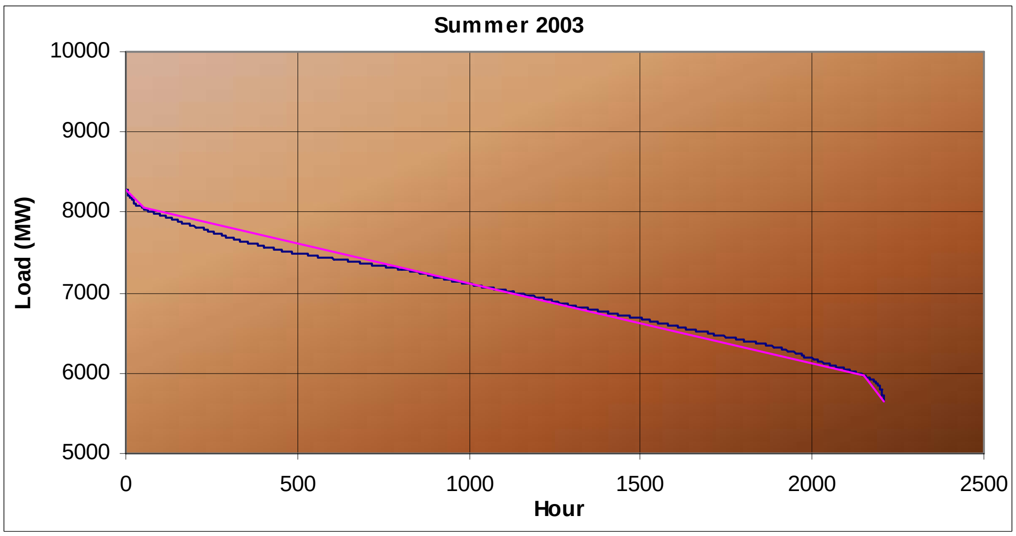


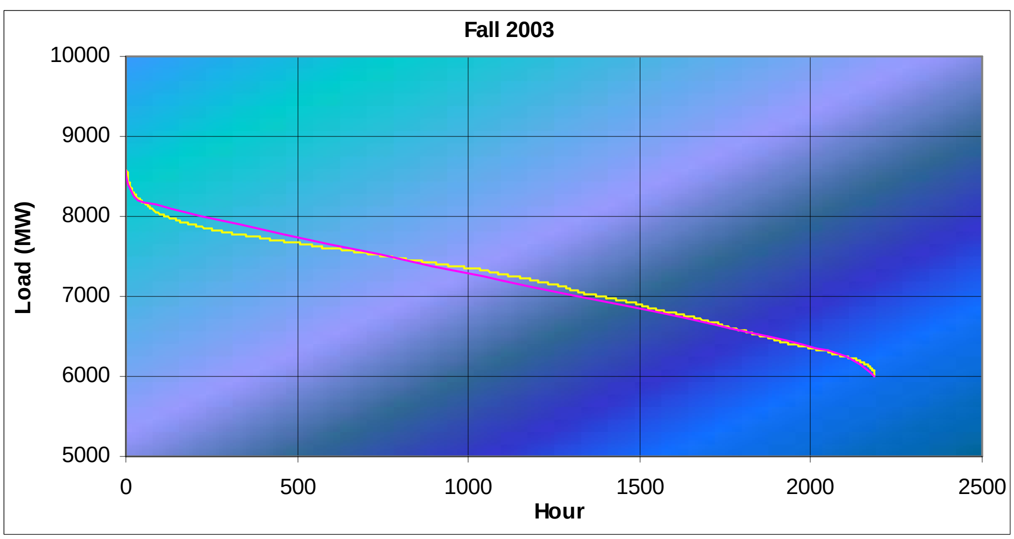
Fall 2002
Load (MW)
10000
9000
8000
7000
6000
5000
0
500
1000
1500
2000
2500
Hour

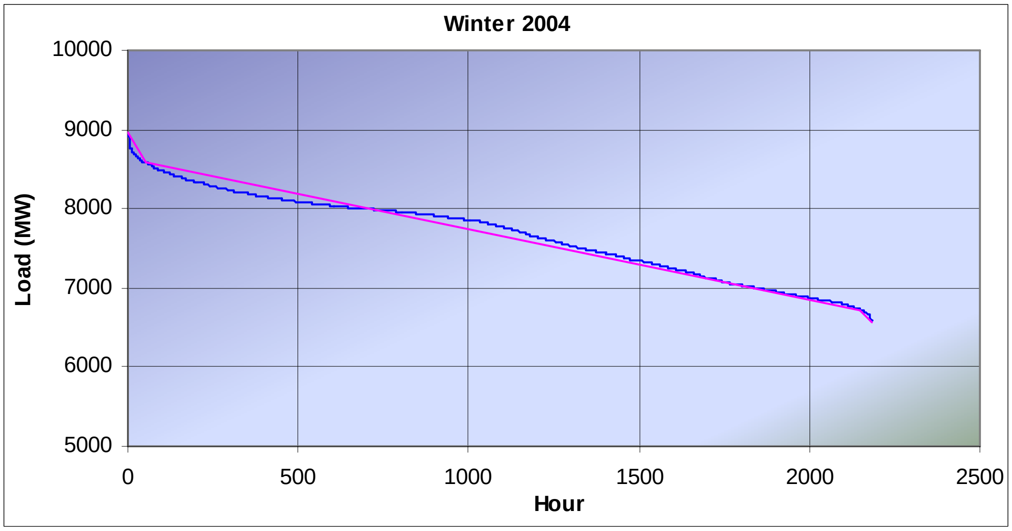


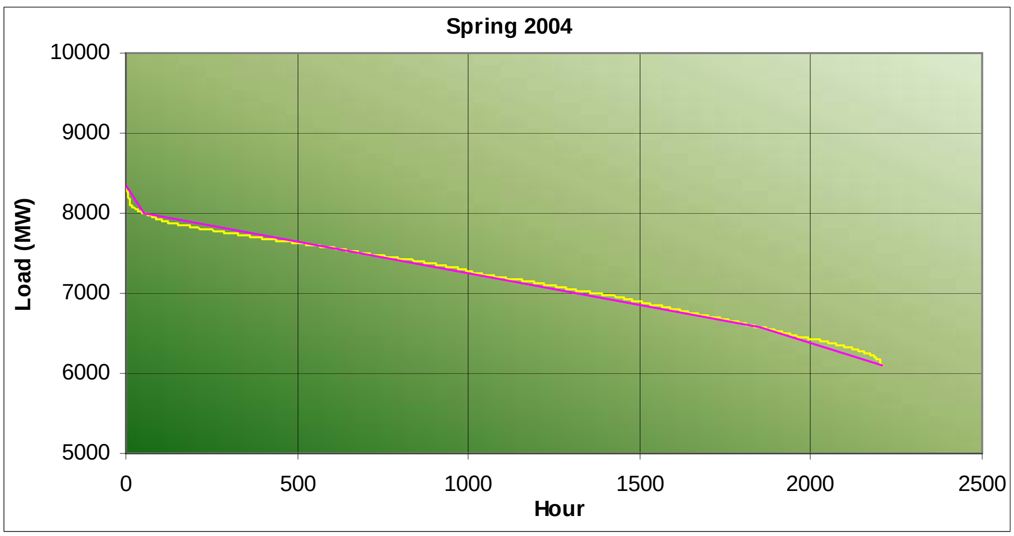
Winter 2003
Load (MW)
10000
9000
8000
7000
6000
5000
0
500
1000
1500
2000
2500
Hour

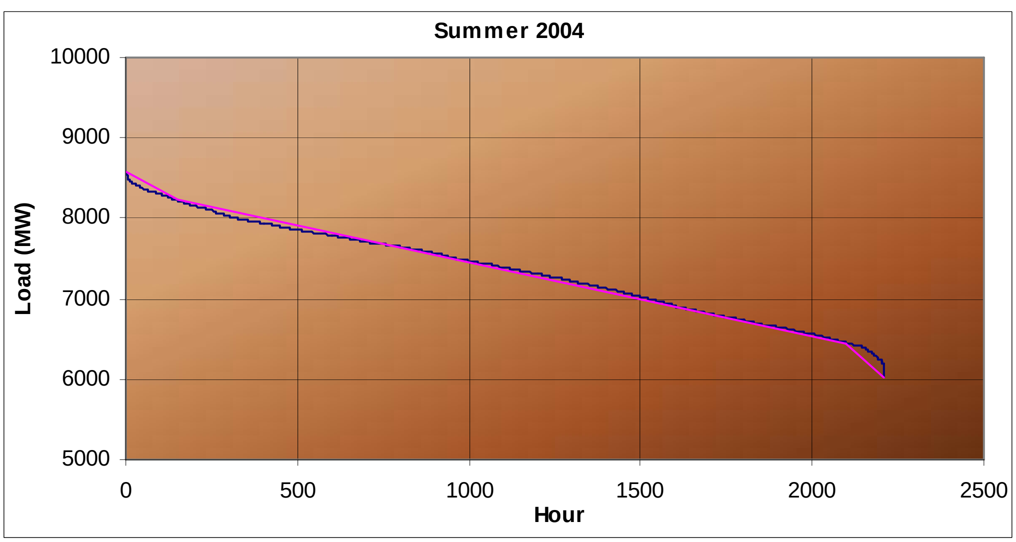

Spring 2003
Load (MW)
10000
9000
8000
7000
6000
5000
0
500
1000
1500
2000
2500
Hour

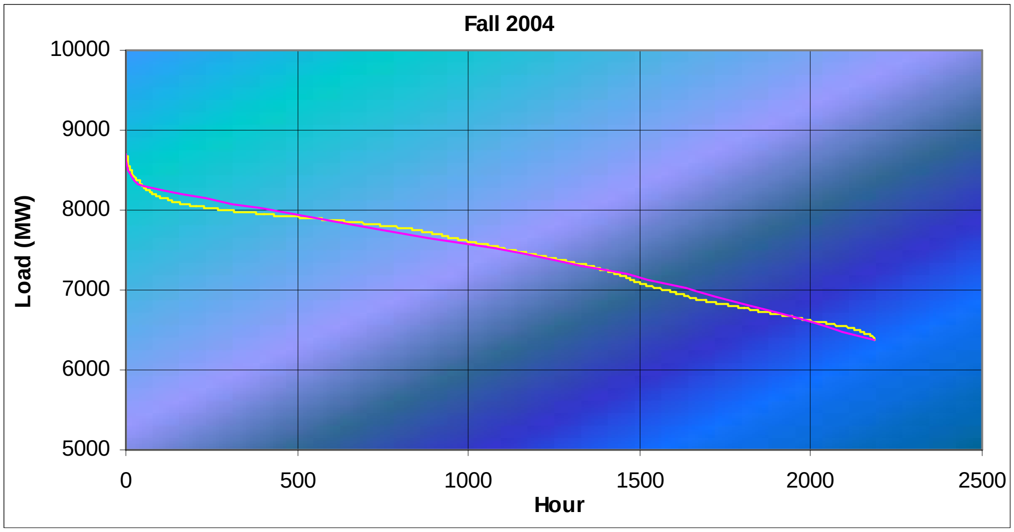

Summer 2003
Load (MW)
10000
9000
8000
7000
6000
5000
0
500
1000
1500
2000
2500
Hour


Fall 2003
Load (MW)
10000
9000
8000
7000
6000
5000
0
500
1000
1500
2000
2500
Hour


Winter 2004
10000
9000
8000
7000
6000
5000
Load (MW)
0
500
1000
1500
2000
2500
Hour

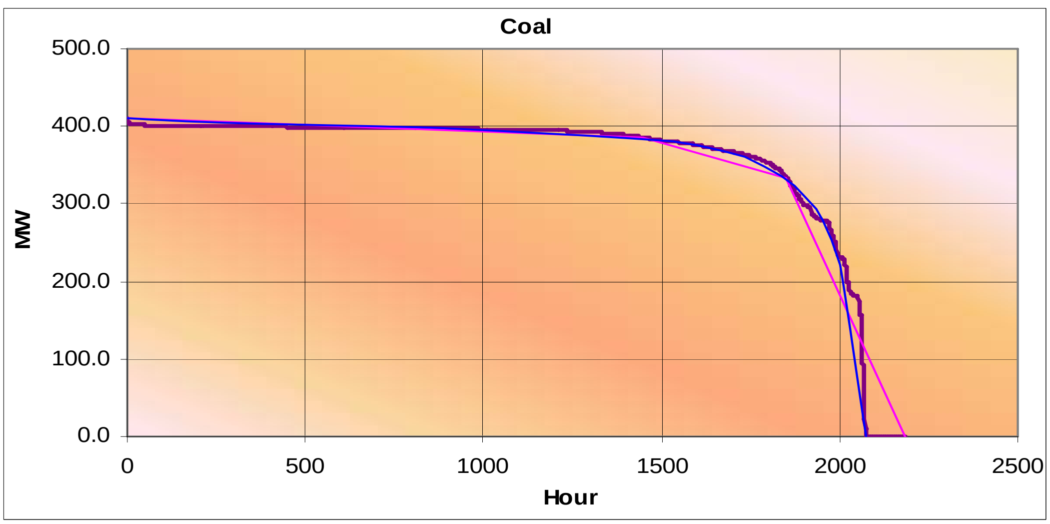

Spring 2004
10000
9000
8000
7000
6000
5000
Load (MW)
0
500
1000
1500
2000
2500
Hour

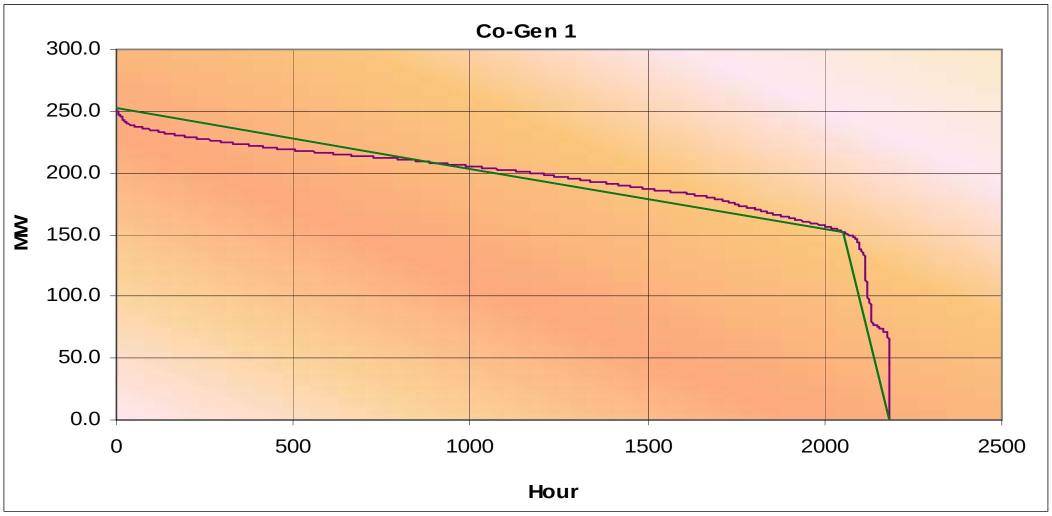

Summer 2004
10000
9000
8000
7000
6000
5000
Load (MW)
0
500
1000
1500
2000
2500
Hour

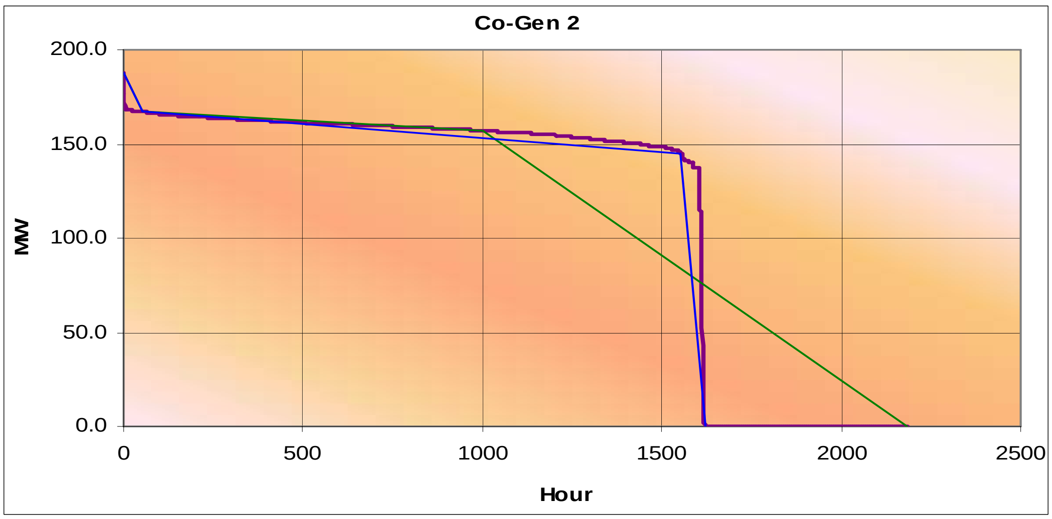


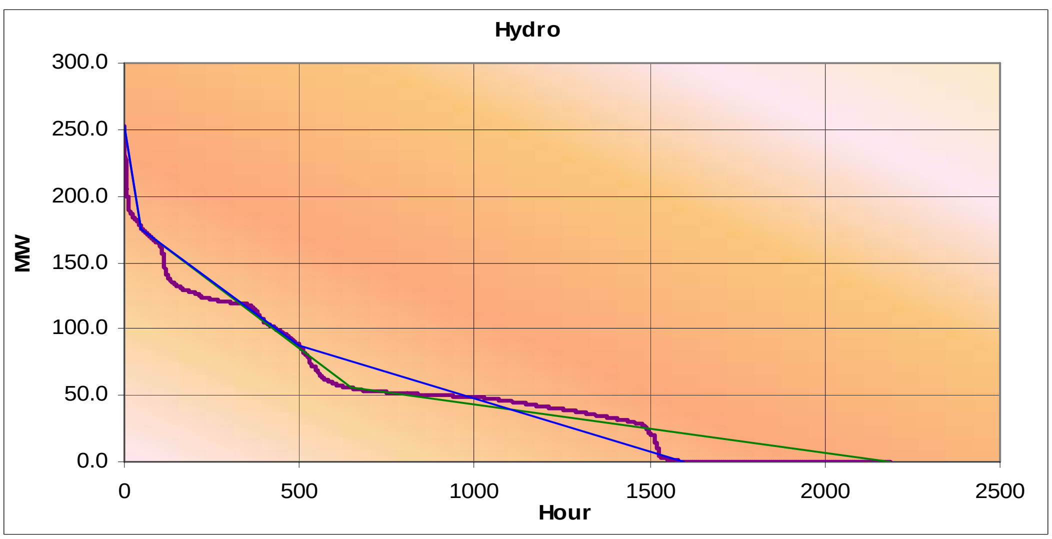
Appendix –B

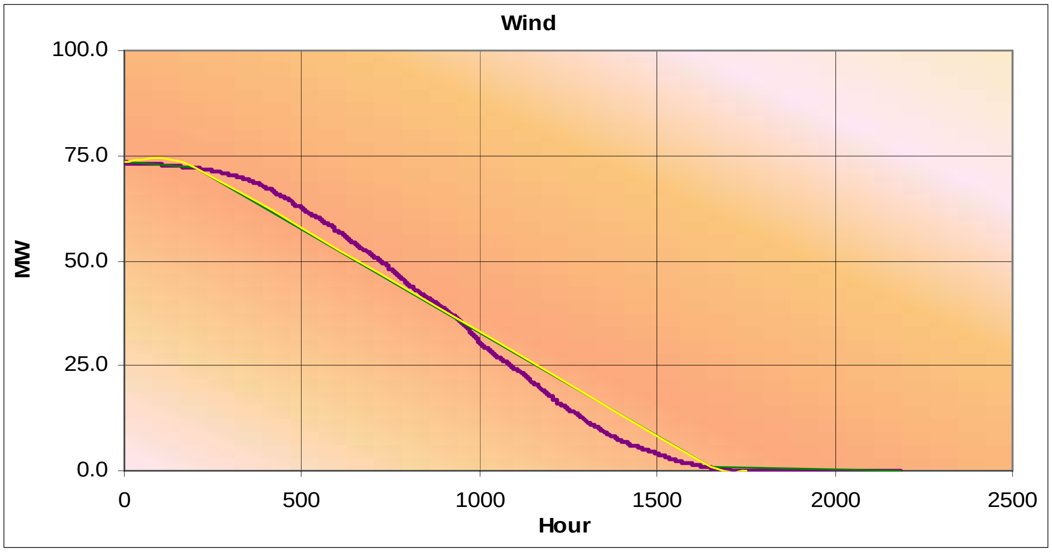
Generation Supply Curves

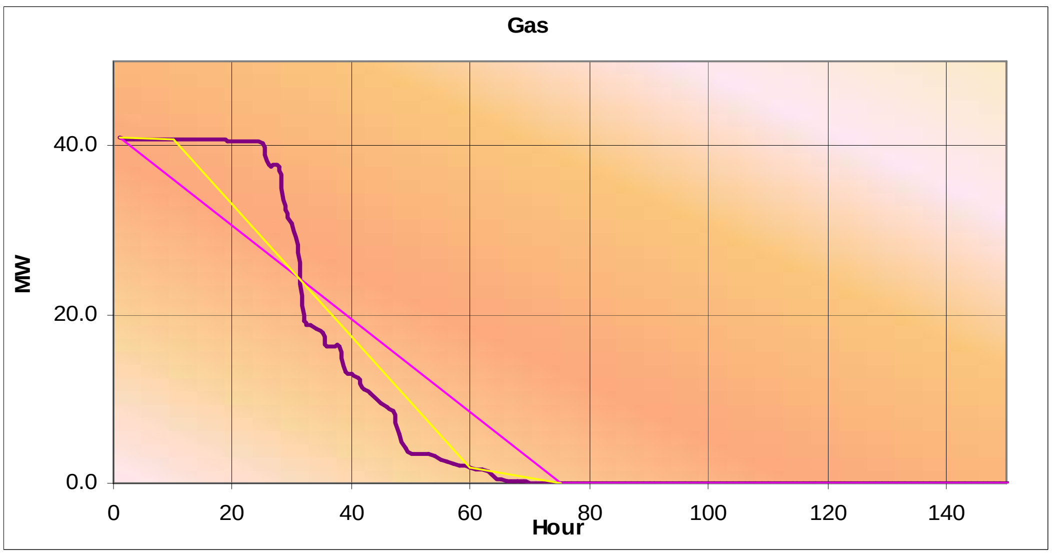



Co-Gen 1
MW
300.0
250.0
200.0
150.0
100.0
50.0
0.0
0
500
1000
1500
2000
2500
Hour


Co-Gen 2
MW
200.0
150.0
100.0
50.0
0.0
0
500
1000
1500
2000
2500
Hour


Hydro
MW
300.0
250.0
200.0
150.0
100.0
50.0
0.0
0
500
1000
1500
2000
2500
Hour


Wind
100.0
75.0
50.0
25.0
0.0
MW
0
500
1000
1500
2000
2500
Hour


Gas
40.0
20.0
0.0
MW
0
20
40
60
80
100
120
140
Hour

Appendix –C

Load Duration Data Analysis

		Percentile			Duration		
Scenario	**Season**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
High	Winter	97.7	97.7	97.8	50	50	50
	Spring	97.8	97.8	97.8	50	50	50
	Summer	97.8	97.8	93.3	50	50	150
	Fall	97.8	97.8	97.8	50	50	50
Medium	Winter				2050	1900	2100
	Spring				2000	2050	1800
	Summer				2050	2100	1950
	Fall				1800	2000	1350
Low	Winter	2.8	9.8	1.6	60	210	34
	Spring	7.2	4.9	16.2	157	107	357
	Summer	4.9	2.7	4.9	108	58	108
	Fall	15.4	6.2	36.0	335	135	785

		Percentile			Duration		
Season	**Scenario**	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Winter	High	97.7	97.7	97.8	50	50	50
	Medium				2050	1900	2100
	Low	2.8	9.8	1.6	60	210	34
Spring	High	97.8	97.8	97.8	50	50	50
	Medium				2000	2050	1800
	Low	7.2	4.9	16.2	157	107	357
Summer	High	97.8	97.8	93.3	50	50	150
	Medium				2050	2100	1950
	Low	4.9	2.7	4.9	108	58	108
Fall	High	97.8	97.8	97.8	50	50	50
	Medium				1800	2000	1350
	Low	15.4	6.2	36.0	335	135	785

THE POWER OF POSSIBILITY

Alberta Electric System Operator

Loss Factor Methodologies Evaluation
Part 1 - Determination of 'Raw' Loss Factors

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada R3T 0P4

December 21, 2004
Revised December 22, 2004
Revised January 24, 2005

File No: 558-10000

DISCLAIMER

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein. This report has been prepared exclusively for the Alberta Electric System Operator (AESO) and the project identified herein and must not be reused or modified without the prior written authorization of Teshmont. This report shall not be reproduced or distributed except in its entirety.

ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION PART 2 CONVERSION OF POWER TO ENERGY LOSS Factors

TABLE OF CONTENTS

Page

ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION PART 2 CONVERSION OF POWER TO ENERGY LOSS FACTORS

1. Introduction

This report discusses the results of full system testing of different methodologies to develop individual generator loss factors to allocate losses to generators for a specific load flow condition.

2. Evaluation Methodology

The full Alberta Integrated Electric System (AIES) was used as the basis for all calculations. A full set of twelve 2003 load flow conditions as used in AESO's current loss factor calculations was used as the reference power flow cases for all alterative methodologies. The load flow model consists of about 1700 busses, among which 730 have generators, loads or both connected. Bus number 1520 (the 500 kV equivalent of the BC Hydro and WECC system) was designated as the swing bus for the system.

Table 1 presents a summary of the twelve load flow solutions. With the exceptions discussed hereinafter, the summary is based on PSLF Version 13.4 accounting methods. In the load flow data, motor loads are modeled as negative generators; so, total PSLF generation reflects the net component. The contributions of the generation and motor load components have been separated out in the tabulation. The tabulation is similar to the tabulation expected from PSS/E with one exception. PSS/E treats all shunt paths as loads (including transformer no-load losses). PSLF treats transformer shunt paths as magnetizing losses; hence, their contribution to the power balance is included in the 'losses' category.

2.1 Approaches to Loss Factor Calculations

2.1.1 Direct Approach

In the direct approach, loss factors are extracted directly from matrix equations describing the relationship between system losses and generation and load at each bus. The equations are examined, and arranged in a form such as the following:

$$\begin{aligned}
\text{Losses} = {} & K_1(Pg_1, Pg_2, --Pg_n, Pl_1, Pl_2, --Pl_n)\cdot Pg_1 \ldots \\
& + K_2(Pg_1, Pg_2, --Pg_n, Pl_1, Pl_2, --Pl_n)\cdot Pg_2 \ldots \\
& + \ldots \\
& + K_n(Pg_1, Pg_2, --Pg_n, Pl_1, Pl_2, --Pl_n)\cdot Pg_n \ldots \\
& + K_0
\end{aligned} \qquad \text{Equation (1)}$$

where Pg_i represents the output of generator "i" and Pl_i represents the magnitude of the load "i".

In the direct method, the loss factor for generator "i" is set to the function:

$$lf_i = K_i(Pg_1, Pg_2, --Pg_n, Pl_1, Pl_2, --Pl_n) \qquad \text{Equation (2)}$$

This function which when evaluated for each generator is multiplied directly by the generator output, providing an indication of the generators contribution to total system losses. The function can therefore be equated to a loss factor.

The term K_0 in Equation (1) represents all components of the total system loss that are independent of generation. This component of the losses is not accounted for during the assignment of losses to generation and therefore will represent the contribution of the direct methodology to the shift factor required to balance the assigned loss equation.

2.1.2 Gradient Method

In the gradient method, the loss factor of a single generator is determined from its marginal impact on transmission losses. The gradient, equal to the change in system losses for a given change in individual unit generation can be calculated analytically by differentiation of Equation (1) or numerically using tools such as a load flow to make small changes to individual generator output, and monitoring the impact of the change in system losses. The raw loss factor for each generator is set equal to the gradient. The gradient method may over or under assign losses resulting in a requirement for a shift factor to balance the loss equation.

2.1.3 Gradient by 2 Method

The gradient method provides a very good estimate of the incremental losses caused by each generator. However, as losses are typically a function of the square of the generation, it does not provide a very good indication of contribution of the total output of the generator to the losses. It can be shown analytically that 100% of the losses can be attributed to both generators and loads based on ½ of their individual gradients. However, as the contributions dues to loads must be assigned to the generators, the contribution to losses can be expressed as a shift factor to each of the generator loss factors to balance the loss equation.

2.2 Calculation of Gradients

2.2.1 Present AESO Swing Bus Method

The present AESO loss factor methodology uses a single swing bus method in which one generator is designated as a swing bus and loss factors are calculated for each other generator based on load flow results. The generator loss factor is equal to the change in losses for a small change in output for the generation for which the loss factor is being calculated. By definition, the raw loss factor of the generator at the swing bus is zero.

2.2.2 Area Load Adjustment

In the area load adjustment method, the generator for which the loss factor is being determined is designated as the swing generator, and load is changed at every bus in the area by a constant ratio. For this calculation the ‘area’ is selected to be the entire Alberta system. Again loss factor is calculated equal to the change in losses for the resultant change in generation at the swing bus.

2.2.3 Partial Differentiation

A third method for calculating gradient based loss factors is to set the loss factor for each generator equal to the partial derivative of the loss equation with respect to the output of the generator. This is a purely mathematical expression for loss factor and there is an underlying assumption that all other contributions to the loss equation remain constant.

The loss factor for each generator based on Equation (1) would be equal to the ‘direct’ loss factor (i.e. the function defined by Equation (2)) plus an additional component equal to the partial derivative of the function with respect to the generator output.

2.3 Solution Methods
In the matrix analysis approaches, loss factors were determined directly from matrices describing the relationship between generator power, bus loads and ac system topology.

The matrix analysis includes an approximate (uncorrected) or exact (corrected) loss matrix describing the dependency of losses on both generation and load. In addition, loss factors were determined using the Kron loss matrix equation in which losses are expressed as only a direct function of generation.

2.4 Methodologies Evaluated
Generator loss factors were determined for each of the methodologies given in Section Three and the results were compared as discussed in Section Four.

3 Methodologies Evaluated

3.1 Uncorrected Loss Matrix (Direct)

In this methodology, the loss factors are determined directly from the coefficients of a system loss matrix.

The system loss matrix is derived from topology and is of the form:

$$R_{uncorr} = \left(\overline{Y^{-1}}\right)^{T} \cdot M^{T} \cdot G \cdot M \cdot Y^{-1} \quad \text{Equation (3)}$$

where:

Y is the nodal admittance matrix for the system
$\left(\overline{Y^{-1}}\right)^{T}$ is the transpose of the conjugate of the inverse of the nodal admittance matrix
M is the branch incidence matrix
G is the diagonal matrix of branch conductance.

The uncorrected ‘R’ matrix is in effect the real component of the inverse of the nodal admittance matrix Y.

Losses can be calculated directly using the expression

$$Losses = \left(\bar{I}\right)^{T} \cdot R \cdot I \quad \text{Equation (4)}$$

Where I is a vector of current injections corresponding to each generator and load bus of the system and $\left(\bar{I}\right)^{T}$ is the transpose of the conjugate of the vector of current injections.

To a first approximation, the loss equation using the system loss matrix can be written in the form:

$$\text{Losses} = \left(P_g + P_l\right)^T \cdot R \cdot \left(P_g + P_l\right) \quad \text{Equation (5)}$$

where P_g contains the generator output (p.u.) and P_l contains the negative values of individual loads (p.u.). Loads are treated as negative generators in this equation.

The equation can be re-written in the form:

$$\text{Losses} = \left(P_g + 2P_l\right)^T \cdot R \cdot P_g + P_l^T \cdot R \cdot P_l \quad \text{Equation (6)}$$

In this expression, losses can be expressed as a function of two components: one component that is independent of generation and another component that is dependent on both load and generation.

The component that is a function of generation is of the form:

$$\text{Losses}_g = \text{LossFactor} \cdot P_g \qquad \text{Equation (7)}$$

where:

$$\text{LossFactor} = \left(P_g + 2P_l\right)^T \cdot R \qquad \text{Equation (8)}$$

In this methodology, loss factors were calculated directly from the above Equation (8).

The loss matrices "R" used in this analysis were the 'uncorrected matrices, based only on system topology.

In this method, the losses that are a function of only the load component are the major contributor to the unassigned losses. There is an additional component due to errors in loss estimation introduced as a result of using an uncorrected loss matrix.

3.2 Corrected Loss Matrix (Direct)

If load flow information (such as bus voltages, angles and generator and load power factors) is available, each individual term of the loss matrix can be 'corrected' by the expression:

$$\zeta_{i,j} = \frac{\cos\left[\left(\phi_i - \phi_j\right) - \left(\sigma_i - \sigma_j\right)\right]}{v_i \cdot v_j \cdot \cos\left(\phi_i\right) \cdot \cos\left(\phi_j\right)} \qquad \text{Equation (9)}$$

$$R_{corr_{i,j}} = R_{uncorr_{i,j}} \cdot \zeta_{i,j} \qquad \text{Equation (10)}$$

where:

subscripts i and j point to elements of the 'R' matrix, corresponding to buses in the system.
ϕ_i and ϕ_j correspond to the net power factor angles at buses i and j respectively.
σ_i and σ_j correspond to the voltage angles at buses i and j respectively.

v_i and v_j correspond to the magnitudes of the voltages at buses i and j respectively.

With these corrections, Equation (5) above becomes an 'exact' numerical expression of losses.

In this set of calculations the corrected loss matrices were used. Corrections were based on bus voltages, bus angles and generator and load power factors obtained from the base-case load flow solutions.

With the corrected loss matrix, Equation (5) above gives exactly the same numerical value for total system losses as the load flow.

3.3 Swing Bus Methodology Using Uncorrected Loss Matrix

Equation (5) above can be used to determine the change in losses for a small change in swing bus and loss factor bus generation.

It can be shown that if the loads are unchanged, the change in total system losses due to change in generation is approximately given by:

$$\Delta \text{Losses} = 2\left(P_g + P_l\right)^T \cdot R \cdot \Delta P_g \quad \text{Equation (10)}$$

It is also known that the change in losses is equal to the sum of the change in losses in all generators, i.e.:

$$\Delta \text{Losses} = \sum_i \Delta P_{g_i} \quad \text{Equation (11)}$$

If generation is assumed to be constant at all but the swing bus and the bus at which the loss factor is being calculated, the above equations reduce to two equations in three unknowns (Δlosses, ΔP_{g1}, ΔP_{gi})

The simultaneous equations can be combined to calculate the ratio:

$$\frac{\Delta \text{Losses}}{\Delta P_{g_i}}$$

which is effectively the definition of raw loss factors used in the present AESO loss factor methodology.

For these calculations, the bus 493 (Clover Bar) was used as the swing bus for the calculations. This is consistent with the present AESO swing bus loss factor methodology.

3.4 Swing Bus Methodology Using Corrected Loss Matrix

The calculation discussed in3.3 above was repeated using the corrected loss matrix. By using the 'corrected loss matrix for this calculation; the set of assumptions change. For the uncorrected loss matrix calculations, it is mathematically exact to assume that the 'R' matrix does not change with small changes in load, as the uncorrected 'R' matrix is a function of only system topology.

Assuming the corrected ‘R’ matrix to be constant implies that all of the corrections made to the ‘R’ matrix are also independent of small changes in generation.

In practice, a small change in generator power output is not likely to significantly alter bus voltages. Load power factors will remain constant, in the same manner as a load flow solution. Generator power factors however are likely to change particularly at the generator where the loss factor is being evaluated and the swing bus. Assuming a constant power factor could lead to undesired consequences.

Any generator operating with a low power factor (for example units connected primarily for var support) would be very susceptible to high loss factor calculations. Assuming the power factor to be constant implies that with every increment in generator output there is a corresponding increase in generator var output. As actual transmission losses are not only a function of MW but also Mvar, the small change in generator output could have a significant impact on total system losses associated with the assumption of a constant ‘R’ matrix. The net result is that low power factor generators could be assessed excessively large loss factor penalties or credits.

A second undesirable effect of this assumption is that some generators could be penalized in terms of increased loss factors for supplying vars to the system under conditions when vars are needed on the system. It is also conceivable that some generators and associated loads could receive credits for taking vars from the system under var shortage conditions.

One method of circumventing this issue is to treat all var injections, from both loads and generators as equivalent constant admittance shunt devices. The nodal admittance matrix must be adjusted to include this effect, before the ‘R’ matrix is established.

The implication of this treatment of load and generator vars is that the load and generator var injections are treated as being constant. Since bus voltages are assumed to be constant, the vars generated by the equivalent shunt devices are also constant. This is again a reasonable approximation for small changes in generator output.

If the power market evolves to include equivalent var loss factors for generators and loads, these assumptions would need to be revisited.

3.5 Area Load Methodology Using Uncorrected Loss Matrix

Equation (5) above can be also be used to determine the change in losses for a small change in swing bus generation and total system load. If all of the loads in the system are increased by a small percentage (say δ), the total change in system losses can be shown to be approximated by the following expression:

$$\Delta \text{Losses} = 2\left(P_g + P_l\right)^T \cdot R \cdot \Delta P_g + \delta \cdot 2 \cdot \left(P_g + P_l\right)^T \cdot R \cdot P_l \qquad \text{Equation (12)}$$

$$\Delta \text{Losses} = \sum_i \Delta P_{g_i} + \delta \cdot \sum_j P_{l_j} \qquad \text{Equation (13)}$$

If only the generation at the loss factor bus changes, then again the above equations can be reduced to two simultaneous equations in three unknowns (Δlosses, ΔP_{g1}, δ)

The simultaneous equations can be combined to again calculate the ratio:

$$\frac{\Delta \text{Losses}}{\Delta P_{g_i}}$$

For this methodology, the generator for which the loss factor is calculated effectively becomes the swing machine for the system. Hence the loss factors calculated are independent of an arbitrary selection of a swing bus in the system.

3.6 Area Load Methodology Using Corrected Loss Matrix

The calculation method discussed in 3.5 above was repeated using the corrected loss matrix. This method is again subject to the limitations introduced by the assumptions regarding the constant 'R' matrix discussed in Section 3.4. Generator and load vars are treated as equivalent shunt devices and hence are indirectly assumed to be constant, by the assumption of constant voltages.

As the main objective of loss factors is to define the relationship between generator power output and transmission losses, it is reasonable to assume that the variation in system load is related only to the power component, i.e., the change in load vars is zero. The assumption of constant load vars in this 'corrected' 'R' matrix methodology is therefore reasonable.

3.7 Uncorrected Loss Matrix (Gradient Method)

The partial derivative of equation 5 above with respect to individual generator output can be determined for each generator as follows:

$$\frac{\partial}{\partial P_{g_i}}(\text{Losses}) = 2\cdot\left(P_g + P_l\right)^T\cdot R\cdot S(i) \qquad \text{Equation (14)}$$

where S(i) is a vector in which the i^{th} element is 1.0 and all other elements are zero.

A vector of all the gradients is simply:

$$\frac{\partial}{\partial P_g}(\text{Losses}) = 2\cdot\left(P_g + P_l\right)^T\cdot R \qquad \text{Equation (15)}$$

The above can be used to allocate losses to generators by multiplying each individual gradient by the generator output.

3.8 Corrected Loss Matrix (Gradient Method)

The calculation discussed in 0 above can be repeated using the corrected loss matrix. Again the loss factors are dependent on the assumption of a constant 'R" matrix. This is a mathematically exact assumption. however the impacts of the assumption are the same as discussed in Section 0. Load and generator var outputs must be assumed to be constant and be embedded in the 'R' matrix to avoid unrealistic penalties and credits for vars supplied or absorbed from the system.

3.9 Uncorrected Loss Matrix (Gradient by 2 Method)

If Equation (15) above is expanded to include all buses for which generation or load is included, it can be combined with Equation (2) to give:

$$\text{Losses} = \left[\frac{\frac{\partial}{\partial P_g}(\text{Losses})}{2}\right] \cdot (P_g + P_l) \qquad \text{Equation (16)}$$

I.e. the total losses of the system can be allocated to load and generation buses based on ½ the gradient calculated for each generator and load bus. The component that is due to generation can be determined from:

$$\text{Losses}_g = \left[\frac{\frac{\partial}{\partial P_g}(\text{Losses})}{2}\right] \cdot P_g \qquad \text{Equation (17)}$$

and the component of the losses due to load is given by:

$$\text{Losses}_l = \left[\frac{\frac{\partial}{\partial P_g}(\text{Losses})}{2}\right] \cdot P_l \qquad \text{Equation (18)}$$

The term $\left[\frac{\frac{\partial}{\partial P_g}(\text{Losses})}{2}\right]$ in Equation (17) can be considered to be a vector of generator raw loss factors and the term "Losses_l" of Equation (18) can be considered to be unassigned losses that are due to loads and which must be factored into the loss balance equation using a shift factor.

One advantage of this methodology is that there is a quantitative explanation of all components of the losses.

3.10 Corrected Loss Matrix (Gradient by 2 Method)

The calculation discussed in 3.9 above can be repeated using the corrected loss matrix. Again the assumption regarding the constant 'R' matrix discussed herein is applicable.

3.11 50% Area Load Methodology, Uncorrected Loss Matrix

It will be shown that the losses assigned by the area load adjustment methodology are almost twice the actual losses. The loss factors calculated using area load adjustment could be reduced by 50% and unassigned losses and shift factor recalculated.

3.12 50% Area Load Methodology, Corrected Loss Matrix

The loss factors calculated using area load adjustment and the corrected loss matrix can also be reduced by 50% and unassigned losses and shift factor recalculated. It will be shown that the unassigned losses and resultant shift factor for this methodology are essentially zero.

Again the assumption regarding the constant 'R' matrix discussed herein is applicable.

3.13 Kron Loss Matrix (Direct Methodology)

An alternative matrix expression of losses used for optimal power flow solutions is the Kron loss matrix formula.

The equation is of the form:

$$\text{Losses} = P_g^T \cdot B02 \cdot P_g + B01 \cdot P_g + B00 \qquad \text{Equation (19)}$$

In the above equation, P_g is a vector housing the magnitude of the real output of the generators. B02 is a matrix, B01 is a vector and B00 is a simple scalar.

The loss equation above can be rewritten in the form:

$$\text{Losses} = \left(P_g^T \cdot B02 + B01\right) \cdot P_g + B00 \qquad \text{Equation (20)}$$

The bracketed term "$\left(2 \cdot P_g^T \cdot B02 + B01\right)$" can be considered to be a vector of raw loss factors as it allocates all but the component "B00" of the losses to the generators. The term B00 represents an unallocated loss component that will contribute to the shift factor.

3.14 Kron Loss Matrix (Swing Bus Methodology)

The Kron loss equation can be rearranged in a similar fashion to the loss matrix equation to determine loss factors based on the existing swing bus methodology.

$$\Delta \text{Losses} = 2 \cdot \left(P_g^T \cdot B02 + B01\right) \cdot \Delta P_g \qquad \text{Equation (21)}$$

It is also known that the change in losses is equal to the sum of the change in losses in all generators, i.e.:

$$\Delta \text{Losses} = \sum_j \Delta P_{g_j} \qquad \text{Equation (22)}$$

If generation is assumed to be constant at all but the swing bus and loss factor bus, the above equations reduce to two equations in three unknowns (ΔLosses, ΔP_{g1}, ΔP_{gi})

The simultaneous equations can be combined to calculate the ratio:

$$\frac{\Delta \text{Losses}}{\Delta P_{g_i}} \qquad \text{Equation (23)}$$

This is effectively the definition of raw loss factors used in the present AESO methodology.

Similar to the corrected loss matrix methods discussed above, this method assumes that the coefficients B02, B01 and B00 are constant. While the coefficients are not as straight forward as the loss matrix 'R' matrix calculations, imbedded in the formulation of the coefficients are corrections for bus voltages, power factors and power angles. As a result, the implications of the assumption of constant coefficients in this methodology are the same as the assumption of constant 'R' matrix in the corrected loss matrix methodologies.

3.15 Kron Loss Matrix (Gradient by 2 Method)

The partial derivative of Equation (19) above can be determined for each generator as follows:

$$\frac{\partial}{\partial P_{g_i}}(\text{Losses}) = \left(2 \cdot P_g^{T} \cdot B02 + B01\right) \cdot S(i) \quad \text{Equation (24)}$$

where S(i) again is a vector in which the i^{th} element is 1.0 and all other elements are zero.

The vector

$$G = 2 \cdot P_g^{T} \cdot B02 + B01 \quad \text{Equation (25)}$$

therefore contains all of the gradients calculated for each generator.

If the gradient is dominated by the first term in Equation (25), the loss equation can be approximated by:

$$\text{Losses} = \frac{G}{2} \cdot P_g + B00 + \varepsilon \quad \text{Equation (26)}$$

where the term ε represents the error introduced by the approximation by ignoring the B01 component and which must be compensated for in the shift factor along with the B00 term.

Again the coefficients B02, B01 and B00 area all assumed to be constant in this methodology. Similar to the loss matrix methodologies discussed in Section 3.8 and 3.10, this is mathematically correct but the implications are the same as discussed in 0 above.

4 Comparison of Methodologies

Loss factors were calculated for every generator in the Alberta system for each of the twelve 2003 base-case load flows and for each of the 15 methodologies discussed in Section 0 above. The results of these calculations are summarized herein.

4.1 Required Shift Factor

Table 12 and **Table 13** summarize the shift factors associated with each load flow and each methodology. The magnitude of the shift factor is a measure of the ability of each methodology to allocate total system losses on a mathematically defined basis. In this context, shift factor is defined to be the correction that must be made to the loss factor for each individual generator to account for all of the unassigned power (MW) losses in the system. A positive shift factor implies that the methodology would result in an under-assignment of total system losses. I.e., the loss factors of each generator must be increased by the shift factor to recover all of the power flow losses. A negative shift factor implies an over-assignment of losses.

The column “Average Loss Factor” is the ratio of losses to total generation as calculated using a load flow program.

The seasonal average shift factors are simply the average of the shift factors for the three load flows of each season. The annual average shift factor is the average of the four seasonal shift factors (equivalent to the average of the shift factors for all 12 load flows). The average shift factors have no physical interpretation, but are useful for comparing the methodologies.

The shift factors shown in Table 2 and Table 3 are the same. In Table 2, the largest and smallest magnitude shift factors encountered for each methodology, for each power flow, are highlighted. In Table 3 the loss factors for each load flow are compared. The largest and smallest magnitude shift factors encountered for each methodology on a load flow basis are highlighted.

Table 2 indicates that there is no apparent correlation between shift factors and load flow or season. For example, the largest shift factor does not always occur for a specific season or load flow condition, independent of methodology. For some methodologies the largest shift factor occurs under winter peak conditions but for others the smallest shift factor occurs for that load flow condition.

Table 3 however does start to indicate a trend in results. The 50% area load adjustment methodologies (both corrected and uncorrected matrices) account for all of the smallest shift factors calculated. The largest shift factors occur with the following methodologies:
uncorrected R matrix, area load adjustment
corrected R matrix, Direct methodology
Kron Matrix, Swing bus methodology

The corrected and uncorrected loss matrix swing bus methodologies require similar shift factors. Both under-allocate losses, and both require shift factors similar in magnitude the current AESO swing bus methodology.

The corrected and uncorrected loss matrix area load adjustments again require similar shift factors. Both over-allocate losses. In fact, both methods over allocate by an amount that is almost equal to the average loss factor, particularly for the corrected loss matrix methodology.

If the loss factors computed with this method are reduced by a factor of 2, resulting in loss factors that are 50% of the area load adjustment methodology; the required shift factor as indicated above is extremely small.

The shift factors required for the uncorrected and corrected loss matrix direct methodologies are not similar in magnitude. This indicates that the methodology is extremely sensitive to assumptions made in the creation of the loss matrix. Both approaches under-assign losses but the shift factors required for the corrected matrix methodology are actually greater than the average system loss factor implying that the total losses accounted for by the methodology are negative.

Similar to the load area adjustment methodology, the loss matrix gradient method significantly over-assigns losses. The corresponding methodology with ½ gradients under-assigns losses, but in this case, the shift factor calculated using the corrected loss matrix is actually greater that the shift factor calculated using an uncorrected matrix. In the corrected matrix, the shift factor is due entirely to the contribution of the system loads to the losses. In the uncorrected method, inaccuracies introduced by the uncorrected loss matrix tend to counteract the effects of the loads. This would not occur if system voltage profiles were lower.

The direct and gradient by 2 Kron matrix methodologies slightly under-assign losses. The gradient by 2 methodology requires the lowest shift factor. The Kron matrix swing bus methodology shows less consistent results between load flows. The Kron matrix methodology is being investigated further to assess the cause of the inconsistencies.

4.2 Range of Loss Factors

The Alberta Department of Energy has indicated that all 'normalized' loss factors must be no greater than twice the average system loss factor and no less than the negative value of the average system loss factor

The range of loss factors after application of the shift factors described in Section 4.1 provides an indication of the extent that loss factors calculated using each methodology would exceed the Department's requirements. Table 14 summarizes the variations in loss factors that could be expected and provides an indication of the degree of ultimate loss factor correction that eventually would have to be applied.

In the table, the "maximum loss factor" is the largest adjusted seasonal loss factor (12 case average) based on individual generators. "Minimum loss factor" is the smallest (or largest negative) value and "range of loss factors" is the difference between the two extremes.

The table also indicates the number of generators with loss factors greater than the criteria and the number of generators with loss factors less than the criteria along with the total. Although the loss factors on which the table is based have been adjusted to take into account and balance all of the power flow losses, an additional correction would be required to take into account differences between load flow losses and forecast generator volumes and losses. The next level of correction will shift the range and as a result, the number of generators with loss factors greater than the maximum permitted may change (say increase), but the number of generators with loss factors less than criteria will also change (i.e. decrease) but the change in total number of generators exceeding the criteria should not be significant.

The Kron matrix direct methodology has the lowest range of loss factors and as a result also has the least number of loss factors that exceed the criteria. The uncorrected loss matrix swing-bus methodology has the largest range and consequently the largest number of generators (86) exceeding the criteria.

4.3 Seasonal Volatility

The Alberta Department of Energy has also indicated that each generator will be assigned a single loss factor. This loss factor will represent the contribution of the generator to losses on an annual basis (at minimum). As the loss factors will be based on some average (weighted or un-weighted) of loss factors calculated using load flows as a starting point, the seasonal volatility of the loss factor becomes an indicator of the degree of accuracy that can be expected when assigning energy based loss factors.

Table 4 also indicates the seasonal volatility of loss factors for each methodology. Volatility is expressed as the largest range in individual generator loss factors over each of the four seasons.

Loss factors calculated using the Kron matrix direct and gradient by 2 methodologies are least sensitive to the variations introduced by the four seasons. This is followed closely by the 50% area load adjustment methodologies and the loss matrix gradient by 2 methods. The range in seasonal volatility for these six methods is from 4.01 to 5.1%.

The uncorrected loss matrix swing bus methodology has the largest seasonal volatility at 11.45%.

4.4 Ranking of Alternative Methodologies.

Each of the methodologies has certain advantages and disadvantages. To quantify the overall assessment of the methodologies, a ranking has been determined for each of the metrics.

The first metric assessed was the load flow adjustment shift factor. Table 3 indicated that the magnitude of shift factor was dependent on not only the methodology but also the individual load flow condition and the season. To assess this metric, the methodologies were ranked for each load flow condition from 1 to 15, depending on the magnitude of load flow shift factor as shown in Table 5. The methodologies were also ranked in terms of the seasonal and annual loss factors from 1 to 15. A ranking of 1 indicates the most desirable while a ranking of 15 is least desirable.

A weighted average of each of the individual rankings was determined for each methodology. The weightings assigned were:

Individual load flows	1/36
Individual Seasons	3/36
Annual Shift Factor	12/36

The weightings effectively give equal weight (1/3) to all of the load flows, all of the seasons and the annual shift factor.

Table 5 indicates that the methodology with the lowest ranking or minimum overall shift factor is the corrected loss matrix, 50% area load adjustment methodology. The methodology with the highest weighted average is the loss matrix direct methodology. The methodologies have been ranked from 1 to 15 based on the weighted average of the individual ranking as shown in the table.

The methodologies have also been ranked from 1 to 15 based on each of the other metrics discussed above. These are:

The number of generators that exceed the loss factor limits
The range of loss factors
Seasonal Volatility

A fifth metric also considered was the dependency of the methodology on selection of swing bus. A problem associated with those methodologies that are dependent on the selection of swing bus for the system is actually designating the appropriate swing. The most appropriate swing bus may need to change with changes in topology and system loading conditions. Those methodologies with no dependence on swing bus selection were assigned a rank of 1 (all tied for 1st place). Those methodologies where there is a dependence on swing bus selection were assigned a ranking of 15 (tied for last place).

Each of the metric rankings were assigned an equal weighting and a weighted sum factoring all of the metrics was determined. The methodology for ranking of alternatives is shown in Table 6. The ranking is based on the weighted sum of the individual rankings.

Based on this assessment method, both loss matrix area load adjustment methodologies rank in the top two, with the corrected l loss matrix method on top followed by the uncorrected loss matrix method.

The direct and gradient by 2 methodologies based on the Kron matrix formula are ranked the same in position 5.

The loss matrix swing bus methodologies are ranked last.

As the methodologies can be separated into two distinct groups, namely those base on corrected matrices and those based on uncorrected matrices, the ranking process describe above was repeated for each group. The comparable rankings are shown in Table 7 and Table 8.

The 50% area load adjustment methodology remains at the top in both categories. The Kron loss formula based methods improve to positions 3 and 4 in the corrected matrix grouping with the direct methodology in position 3. The area load swing bus methodology remains in last place in all groupings.

4.5 Recommendation

Based on the rankings of alternatives, it is clear that the loss matrix 50% area load adjustment methodology is the best approach to allocating losses to generators. The methodology results in a small load flow shift factor. Generator loss factors are independent of the selection of the swing bus for the system. I.e. when the loss factor is calculated for each generator, the bus to which the generator is connected must become the swing bus for the system. The number of generators that are likely to drive loss factor compression is small (in the order of 12) and the extent of compression required is low with a requirement to reduce the loss factor range from about 18.5% to three times the average loss factor or about 15%.

One of the other requirements of the Alberta Department of Energy is that with the chosen methodology, loss factors of nearby (electrical) generators be similar.

Loss factors were calculated for each generator in each of the load flow areas. The results are given in Table 9 for the corrected loss matrix and Table 10 for the uncorrected loss matrix, 50% area load adjustment methodologies. In Table 9, the variation in adjusted loss factors varies from as low as 0.05% in load flow area 43 (Sheerness) to as high as 7.03% in load flow area 97 (designated as "IPP site"). The variation in area 40 (Lake Wabamun accounting for the majority of the Alberta system generation) is only 0.76%.

Although there is a slight shift in the loss factors within each area when calculated with the uncorrected loss matrix the range remains about the same, in particular in area 40 where the range of loss factor variation remains low at 1.31%.

A comparison of the average loss factors for each of the load flow areas and for both the corrected and un-corrected loss matrices is given in Figure 10. The pattern evident in the average loss factors for each load flow area for the uncorrected matrix methodology is similar to the corresponding pattern with the corrected matrix methodology. However, the loss factors (both penalties and credits) are sufficiently different so as to limit the usefulness of the uncorrected matrix methodology.

The uncorrected matrix methodology has advantages in terms of transparency. These methodologies eliminate the variation introduced into the loss factor calculation as a result of load flow solution.

For the existing methodology, loss factors for all new generators are based on information deemed to be confidential by the generators. This information is embedded in the load flows and as a result, the load flows themselves have also been deemed to be confidential. If the loss factor calculations were based on an uncorrected loss matrix, the calculation would be dependent only on system topology and assumed distribution of generation and loads. System topology and data is openly available through TASMO. The distribution of loads is not considered confidential and the stacking order for generation is public information. The only unavailable quantity would be the amount of generation assumed for each entry in the stacking order as this information is considered to be confidential. It should be possible, however, to establish a reasonable estimate of the generation distribution based on historical system performance and posted representative system load flows.

If an approach to loss factor calculations is adopted that is based on historical utilization of the transmission system by each generator, the confidentiality issue may disappear, and all aspects of the loss factor calculations could become public.

In this case, the value of the uncorrected matrix methodologies diminishes. The corrected matrix methodology should be adopted because of its more accurate distribution of load flow losses.

The recommended methodology therefore for determining load flow based 'raw' loss factors is the corrected loss matrix, 50 % area load adjustment methodology.

Table 1 Load Flow Solution Summary

	WnPk	WnMd	WnLw	SpPk	SpMd	SpLw	SmPk	SmMd	SmLw	FlPk	FlMd	FlLw
Total Generation	**8456.8**	**7845.7**	**7548.6**	**7978.7**	**7554.2**	**7297.3**	**8269.2**	**7594.3**	**7331.2**	**8390.3**	**7737.9**	**7459.0**
Generation	8423.8	7812.7	7515.6	7945.7	7521.2	7264.3	8236.2	7561.3	7298.2	8357.3	7704.9	7426.0
Negative loads	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Total Imports	**258.9**	**-8.3**	**-604.1**	**98.0**	**-70.3**	**-673.3**	**94.6**	**-33.1**	**-706.8**	**433.4**	**3.6**	**-619.1**
SPC Imports	100.0	-0.1	-75.0	100.0	0.0	-75.0	100.0	-0.1	-75.0	100.0	0.0	-75.0
BC Imports	158.9	-8.2	-529.1	-2.0	-70.3	-598.3	-5.4	-33.0	-631.8	333.4	3.6	-544.1
Total Loads	**8345.3**	**7473.8**	**6536.0**	**7718.0**	**7144.5**	**6236.6**	**8020.0**	**7229.3**	**6236.2**	**8468.4**	**7393.4**	**6449.7**
Constant P Loads	8043.6	7172.4	6234.4	7453.2	6879.6	5971.6	7725.8	6935.1	5942.0	8173.4	7098.4	6154.7
Motor Loads	276.2	276.2	276.2	239.4	239.4	239.4	294.2	294.2	294.2	295.0	295.0	295.0
Shunts	25.5	25.2	25.3	25.4	25.4	25.6	0.0	0.0	0.0	0.0	0.0	0.0
Load Flow Losses	**370.5**	**363.5**	**408.5**	**358.7**	**339.5**	**387.4**	**343.8**	**331.9**	**388.2**	**355.3**	**348.1**	**390.2**
Generation + imports less loads	370.5	363.5	408.5	358.7	339.5	387.4	343.8	331.9	388.2	355.3	348.1	390.2
Mismatch	**0.000**	**0.001**	**0.039**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

Table 2 Load Flow Shift Factors Required For Each Methodology (Part “a”)

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology
WnPk	4.77%	2.07%	1.43%	-4.79%	-4.57%	-0.01%	0.10%	2.07%	7.87%
WnMd	5.16%	3.75%	2.88%	-5.25%	-4.99%	-0.04%	0.09%	1.73%	7.47%
WnLw	6.42%	4.19%	3.99%	-7.82%	-6.37%	-0.70%	0.02%	0.86%	6.58%
SpPk	5.01%	2.06%	1.48%	-4.93%	-4.84%	0.04%	0.09%	1.91%	7.87%
SpMd	5.05%	3.30%	2.43%	-5.09%	-4.90%	-0.02%	0.07%	1.63%	8.21%
SpLw	6.41%	3.38%	3.37%	-7.66%	-6.47%	-0.62%	-0.03%	0.93%	6.85%
SmPk	4.32%	1.69%	1.20%	-4.80%	-4.15%	-0.24%	0.08%	1.79%	6.67%
SmMd	4.55%	3.44%	2.67%	-5.12%	-4.42%	-0.29%	0.06%	1.34%	6.43%
SmLw	6.03%	3.04%	3.43%	-8.02%	-6.05%	-0.99%	-0.01%	0.57%	5.93%
FlPk	4.22%	1.03%	0.58%	-4.50%	-4.06%	-0.14%	0.08%	0.57%	6.26%
FlMd	4.65%	3.70%	2.93%	-5.36%	-4.53%	-0.35%	0.06%	1.30%	5.64%
FlLw	5.86%	3.24%	3.42%	-7.70%	-5.86%	-0.92%	0.00%	0.74%	5.55%
Winter Average		3.34%	2.77%	-5.95%	-5.31%	-0.25%	0.07%	1.55%	7.31%
Spring Average		2.91%	2.43%	-5.90%	-5.40%	-0.20%	0.04%	1.49%	7.64%
Summer Average		2.72%	2.43%	-5.98%	-4.88%	-0.51%	0.04%	1.23%	6.34%
Fall Average		2.66%	2.31%	-5.85%	-4.82%	-0.47%	0.05%	0.87%	5.82%
Annual Average		2.91%	2.48%	-5.92%	-5.10%	-0.36%	0.05%	1.29%	6.78%

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix
Loading Condition	Average Loss Factor	Gradient Methodology	Gradient Methodology	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology
WnPk	4.77%	-2.84%	-0.70%	0.96%	2.03%	1.19%	-11.95%	0.65%
WnMd	5.16%	-3.62%	-1.84%	0.77%	1.66%	1.28%	-7.63%	0.68%
WnLw	6.42%	-6.77%	-5.72%	-0.18%	0.35%	1.82%	2.50%	0.40%
SpPk	5.01%	-3.19%	-1.67%	0.91%	1.67%	1.26%	-9.02%	0.70%
SpMd	5.05%	-3.66%	-2.16%	0.69%	1.45%	1.27%	-5.68%	0.75%
SpLw	6.41%	-6.87%	-7.16%	-0.23%	-0.37%	1.98%	9.49%	0.38%
SmPk	4.32%	-2.95%	-0.43%	0.68%	1.94%	0.91%	-11.19%	0.49%
SmMd	4.55%	-3.66%	-1.85%	0.44%	1.35%	0.90%	-5.28%	0.47%
SmLw	6.03%	-7.14%	-6.41%	-0.55%	-0.19%	1.72%	5.81%	0.06%
FlPk	4.22%	-2.61%	-0.51%	0.81%	1.86%	0.86%	-12.00%	0.46%
FlMd	4.65%	-3.81%	-2.09%	0.42%	1.28%	0.89%	-5.52%	0.39%
FlLw	5.86%	-6.77%	-5.73%	-0.45%	0.07%	1.47%	3.33%	0.11%
Winter Average		-4.41%	-2.75%	0.52%	1.35%	1.43%	-5.69%	0.58%
Spring Average		-4.57%	-3.66%	0.46%	0.92%	1.50%	-1.74%	0.61%
Summer Average		-4.58%	-2.90%	0.19%	1.03%	1.18%	-3.55%	0.34%
Fall Average		-4.40%	-2.78%	0.26%	1.07%	1.07%	-4.73%	0.32%
Annual Average		-4.49%	-3.02%	0.36%	1.09%	1.29%	-3.93%	0.46%

Legend
Largest Shift Factor per Methodology
Smallest Shift Factor per Methodology

Table 3 Load Flow Shift Factors Required For Each Methodology (Part "b")

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology
WnPk	4.77%	2.07%	1.43%	-4.79%	-4.57%	-0.01%	0.10%	2.07%	7.87%
WnMd	5.16%	3.75%	2.88%	-5.25%	-4.99%	-0.04%	0.09%	1.73%	7.47%
WnLw	6.42%	4.19%	3.99%	-7.82%	-6.37%	-0.70%	0.02%	0.86%	6.58%
SpPk	5.01%	2.06%	1.48%	-4.93%	-4.84%	0.04%	0.09%	1.91%	7.87%
SpMd	5.05%	3.30%	2.43%	-5.09%	-4.90%	-0.02%	0.07%	1.63%	8.21%
SpLw	6.41%	3.38%	3.37%	-7.66%	-6.47%	-0.62%	-0.03%	0.93%	6.85%
SmPk	4.32%	1.69%	1.20%	-4.80%	-4.15%	-0.24%	0.08%	1.79%	6.67%
SmMd	4.55%	3.44%	2.67%	-5.12%	-4.42%	-0.29%	0.06%	1.34%	6.43%
SmLw	6.03%	3.04%	3.43%	-8.02%	-6.05%	-0.99%	-0.01%	0.57%	5.93%
FlPk	4.22%	1.03%	0.58%	-4.50%	-4.06%	-0.14%	0.08%	0.57%	6.26%
FlMd	4.65%	3.70%	2.93%	-5.36%	-4.53%	-0.35%	0.06%	1.30%	5.64%
FlLw	5.86%	3.24%	3.42%	-7.70%	-5.86%	-0.92%	0.00%	0.74%	5.55%
Winter Average		3.34%	2.77%	-5.95%	-5.31%	-0.25%	0.07%	1.55%	7.31%
Spring Average		2.91%	2.43%	-5.90%	-5.40%	-0.20%	0.04%	1.49%	7.64%
Summer Average		2.72%	2.43%	-5.98%	-4.88%	-0.51%	0.04%	1.23%	6.34%
Fall Average		2.66%	2.31%	-5.85%	-4.82%	-0.47%	0.05%	0.87%	5.82%
Annual Average		2.91%	2.48%	-5.92%	-5.10%	-0.36%	0.05%	1.29%	6.78%

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix
Loading Condition	Average Loss Factor	Gradient Methodology	Gradient Methodology	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology
WnPk	4.77%	-2.84%	-0.70%	0.96%	2.03%	1.19%	-11.95%	0.65%
WnMd	5.16%	-3.62%	-1.84%	0.77%	1.66%	1.28%	-7.63%	0.68%
WnLw	6.42%	-6.77%	-5.72%	-0.18%	0.35%	1.82%	2.50%	0.40%
SpPk	5.01%	-3.19%	-1.67%	0.91%	1.67%	1.26%	-9.02%	0.70%
SpMd	5.05%	-3.66%	-2.16%	0.69%	1.45%	1.27%	-5.68%	0.75%
SpLw	6.41%	-6.87%	-7.16%	-0.23%	-0.37%	1.98%	9.49%	0.38%
SmPk	4.32%	-2.95%	-0.43%	0.68%	1.94%	0.91%	-11.19%	0.49%
SmMd	4.55%	-3.66%	-1.85%	0.44%	1.35%	0.90%	-5.28%	0.47%
SmLw	6.03%	-7.14%	-6.41%	-0.55%	-0.19%	1.72%	5.81%	0.06%
FlPk	4.22%	-2.61%	-0.51%	0.81%	1.86%	0.86%	-12.00%	0.46%
FlMd	4.65%	-3.81%	-2.09%	0.42%	1.28%	0.89%	-5.52%	0.39%
FlLw	5.86%	-6.77%	-5.73%	-0.45%	0.07%	1.47%	3.33%	0.11%
Winter Average		-4.41%	-2.75%	0.52%	1.35%	1.43%	-5.69%	0.58%
Spring Average		-4.57%	-3.66%	0.46%	0.92%	1.50%	-1.74%	0.61%
Summer Average		-4.58%	-2.90%	0.19%	1.03%	1.18%	-3.55%	0.34%
Fall Average		-4.40%	-2.78%	0.26%	1.07%	1.07%	-4.73%	0.32%
Annual Average		-4.49%	-3.02%	0.36%	1.09%	1.29%	-3.93%	0.46%

Legend
Largest Shift Factor Per Load Flow or Season
Smallest Shift Factor Per Load Flow or Season

Table 4 Range of Loss Factors per Methodology

	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology
Maximum Loss Factor	28.72%	18.88%	26.57%	17.82%	15.89%	11.51%	16.15%	7.95%
Minimum Loss Factor	-33.14%	-21.29%	-29.76%	-19.21%	-12.28%	-7.00%	-18.13%	-24.16%
Range of Loss Factors	61.86%	40.17%	56.33%	37.03%	28.17%	18.52%	34.28%	32.12%
No. Greater Than Maximum Permitted	20	20	20	20	19	3	17	0
No. Less Than Minimum Permitted	66	60	63	58	38	9	41	19
No of Generators Exceeding Criteria	86	80	83	78	57	12	58	19
Seasonal Volatility	11.45%	11.37%	10.22%	10.31%	4.87%	4.92%	8.07%	6.78%

	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix
	Gradient Methodology	Gradient Methodology	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology
Maximum Loss Factor	26.91%	18.12%	16.06%	11.66%	10.33%	17.29%	11.23%
Minimum Loss Factor	-30.34%	-19.77%	-12.57%	-7.28%	-5.30%	-18.06%	-6.35%
Range of Loss Factors	57.25%	37.89%	28.62%	18.95%	15.62%	35.35%	17.57%
No. Greater Than Maximum Permitted	20	20	20	3	0	20	3
No. Less Than Minimum Permitted	64	60	40	9	1	57	2
No of Generators Exceeding Criteria	84	80	60	12	1	77	5
Seasonal Volatility	10.43%	10.69%	4.98%	5.10%	4.01%	9.02%	4.46%

Legend
Largest Magnitude per Methodolgy
Smallest Magnitude per Methodology

Table 5 Ranking of Methodologies Based on Magnitude of Shift Factor

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology
WnPk	4.77%	10	7	13	12	1	2	9	14
WnMd	5.16%	11	9	13	12	1	2	7	14
WnLw	6.42%	10	9	15	12	5	1	6	13
SpPk	5.01%	10	6	13	12	1	2	9	14
SpMd	5.05%	10	9	13	12	1	2	7	15
SpLw	6.41%	9	8	14	10	5	1	6	11
SmPk	4.32%	8	7	13	12	2	1	9	14
SmMd	4.55%	10	9	13	12	2	1	6	15
SmLw	6.03%	8	9	15	12	6	1	5	11
FlPk	4.22%	9	6	13	12	2	1	5	14
FlMd	4.65%	10	9	13	12	2	1	7	15
FlLw	5.86%	8	10	15	13	6	1	5	11
Winter Average		10	9	14	12	2	1	7	15
Spring Average		10	9	14	13	2	1	6	15
Summer Average		9	8	14	13	4	1	7	15
Fall Average		9	8	15	13	4	1	5	14
Annual Average		9	8	14	13	3	1	6	15
Weighted Average		9.31	8.22	13.94	12.56	2.94	1.11	6.33	14.39
Overall Ranking		9	8	14	13	3	1	6	15

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix
Loading Condition	Average Loss Factor	Gradient Methodology	Gradient Methodology	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology
WnPk	4.77%	11	4	5	8	6	15	3
WnMd	5.16%	10	8	4	6	5	15	3
WnLw	6.42%	14	11	2	3	7	8	4
SpPk	5.01%	11	7	4	8	5	15	3
SpMd	5.05%	11	8	3	6	5	14	4
SpLw	6.41%	12	13	2	3	7	15	4
SmPk	4.32%	11	3	5	10	6	15	4
SmMd	4.55%	11	8	3	7	5	14	4
SmLw	6.03%	14	13	4	3	7	10	2
FlPk	4.22%	11	4	7	10	8	15	3
FlMd	4.65%	11	8	4	6	5	14	3
FlLw	5.86%	14	12	4	2	7	9	3
Winter Average		11	8	3	5	6	13	4
Spring Average		12	11	3	5	7	8	4
Summer Average		12	10	2	5	6	11	3
Fall Average		11	10	2	6	7	12	3
Annual Average		12	10	2	5	7	11	4
Weighted Average		11.75	9.33	2.81	5.42	6.53	11.75	3.61
Overall Ranking		11	10	2	5	7	11	4

Legend
- Largest Ranking Per Load Flow or Season
- Smallest Ranking Per Load Flow or Season

Table 6 Overall Ranking Of Methodologies

Criteria	Weighting	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology
Shift Factor	1	9	8	14	13	3	1	6	15
Number of Generators That Exceed the Limits	1	15	11	13	10	6	3	7	5
Range of Loss Factors	1	15	12	13	10	5	3	8	7
Seasonal Volatility	1	15	14	10	11	3	4	8	7
Swing Independent	1	15	15	1	1	1	1	1	1
Weighted Sum		13.80	12.00	10.20	9.00	3.60	2.40	6.00	7.00
Final Ranking		15	14	11	9	2	1	7	8

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Criteria	Weighting	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology
Shift Factor	1	11	10	2	5	7	11	4
Number of Generators That Exceed the Limits	1	14	11	8	3	1	9	2
Range of Loss Factors	1	14	11	6	4	1	9	2
Seasonal Volatility	1	12	13	5	6	1	9	2
Swing Independent	1	1	1	1	1	15	15	15
Weighted Sum		10.40	9.20	4.40	3.80	5.00	10.60	5.00
Final Ranking		12	10	4	3	5	13	5

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 7 Overall Ranking Of Corrected Matrix Methodologies

Criteria	Weighting	Corrected R-matrix Swing Bus Methodology	Corrected R-matrix Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Corrected R-matrix Direct Methodology	Corrected R-matrix Gradient Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology
Shift Factor	1	5	8	1	9	6	3	4	7	2
Number of Generators That Exceed the Limits	1	8	7	3	5	8	3	1	6	2
Range of Loss Factors	1	9	7	3	5	8	4	1	6	2
Seasonal Volatility	1	9	7	3	5	8	4	1	6	2
Swing Independent	1	9	1	1	1	1	1	9	9	9
Weighted Sum		8.00	6.00	2.20	5.00	6.20	3.00	3.20	6.80	3.40
Final Ranking		9	6	1	5	7	2	3	8	4

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 8 Overall Ranking Of Uncorrected Matrix Methodologies

Criteria	Weighting	Uncorrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Uncorrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology
Shift Factor	1	4	6	2	3	5	1
Number of Generators That Exceed the Limits	1	6	4	1	2	5	3
Range of Loss Factors	1	6	4	1	3	5	2
Seasonal Volatility	1	6	4	1	3	5	2
Swing Independent	1	6	1	1	1	1	1
Weighted Sum		5.60	3.80	1.20	2.40	4.20	1.80
Final Ranking		6	4	1	3	5	2

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 9 Loss Factors by Load Flow Area, 50% Area Load Corrected Matrix Methodology

Area	Average	Maximum	Minimum	Range
4	-5.81%	-5.66%	-5.93%	0.27%
6	-3.09%	-2.73%	-3.46%	0.74%
15	-4.16%	-4.16%	-4.16%	0.00%
17	-3.90%	-3.35%	-4.05%	0.70%
19	-2.67%	-2.67%	-2.67%	0.00%
20	-4.60%	-2.57%	-7.00%	4.44%
22	0.68%	0.68%	0.68%	0.00%
23	-0.33%	0.09%	-0.54%	0.63%
25	8.92%	9.24%	8.63%	0.62%
26	4.01%	4.01%	4.01%	0.00%
27	3.26%	3.26%	3.26%	0.00%
28	9.40%	11.10%	8.26%	2.84%
30	0.88%	1.12%	0.50%	0.62%
33	3.78%	4.23%	3.04%	1.19%
34	-0.10%	0.02%	-0.22%	0.24%
35	1.59%	1.85%	1.41%	0.43%
36	3.74%	4.18%	2.92%	1.26%
40	6.11%	6.42%	5.67%	0.76%
43	1.04%	1.07%	1.02%	0.05%
44	-4.33%	-3.89%	-4.86%	0.98%
45	-2.55%	-1.81%	-3.31%	1.50%
53	-2.80%	-1.58%	-3.77%	2.19%
55	-3.89%	-3.01%	-4.77%	1.77%
60	3.94%	3.97%	3.84%	0.13%
91	10.24%	11.51%	9.98%	1.53%
92	8.88%	8.97%	8.82%	0.14%
97	-2.17%	2.33%	-4.69%	7.03%

Legend	
	Maximum
	Minimum
	Range > 2% < max

Table 10 Loss Factors by Load Flow Area, 50% Area Load Uncorrected Matrix Methodology

Area	Average	Maximum	Minimum	Range
4	-7.51%	-7.31%	-7.66%	0.35%
6	-4.34%	-3.99%	-4.70%	0.70%
15	-6.41%	-6.41%	-6.41%	0.00%
17	-12.04%	-11.28%	-12.28%	1.00%
19	-5.12%	-5.12%	-5.12%	0.00%
20	-6.15%	-3.74%	-9.00%	5.26%
22	-0.10%	-0.10%	-0.10%	0.00%
23	-1.05%	-0.54%	-1.31%	0.78%
25	12.30%	12.66%	11.95%	0.70%
26	3.99%	3.99%	3.99%	0.00%
27	3.98%	3.98%	3.98%	0.00%
28	11.82%	13.84%	10.39%	3.45%
30	0.35%	0.54%	0.01%	0.53%
33	4.20%	4.53%	3.64%	0.89%
34	-0.69%	-0.57%	-0.82%	0.25%
35	0.90%	1.13%	0.75%	0.39%
36	2.77%	3.28%	1.82%	1.46%
40	5.98%	6.46%	5.15%	1.31%
43	-0.72%	-0.70%	-0.74%	0.04%
44	-5.88%	-5.12%	-6.84%	1.72%
45	-3.97%	-3.15%	-4.80%	1.65%
53	-5.00%	-3.83%	-6.06%	2.23%
55	-6.01%	-5.00%	-7.03%	2.04%
60	4.14%	4.16%	4.10%	0.06%
91	13.83%	15.89%	13.43%	2.46%
92	12.23%	12.33%	12.17%	0.16%
97	-3.83%	1.95%	-6.92%	8.88%

Legend	
	Maximum
	Minimum
	Range > 2% < max

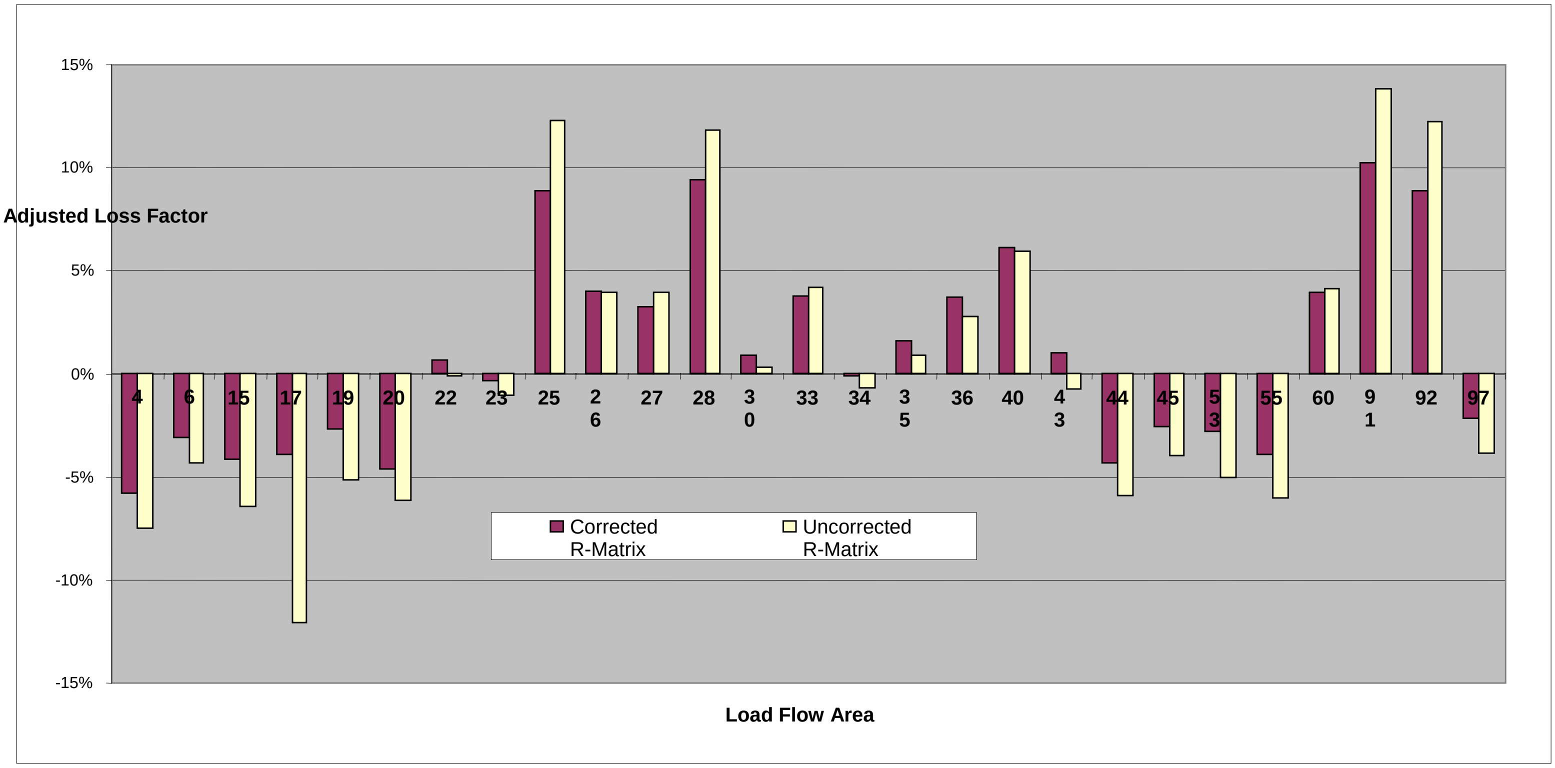


Figure 10 Comparison of Adjusted Average Loss Factors Using Corrected and Uncorrected R-Matrices

THE POWER OF POSSIBILITY

Alberta Electric System Operator

Loss Factor Methodologies Evaluation Part 1

Determination of 'Raw' Loss Factors and Load Flow Shift Factors

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada R3T 0P4

December 21, 2004
Revised December 22, 2004
Revised January 24, 2005
Revised October 31, 2005

File No: 558-10000

DISCLAIMER

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein. This report has been prepared exclusively for the Alberta Electric System Operator (AESO) and the project identified herein and must not be reused or modified without the prior written authorization of Teshmont. This report shall not be reproduced or distributed except in its entirety.

ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION
PART 1 - DETERMINATION OF 'RAW' LOSS FACTORS

TABLE OF CONTENTS

Page

LOSS FACTOR METHODOLOGIES EVALUATION
PART 1 - DETERMINATION OF 'RAW' LOSS FACTORS

1. Introduction
This report discusses the results of full system testing of different methodologies to develop individual generator loss factors to allocate losses to generators for a specific load flow condition.

2. Evaluation Methodology
The Alberta Integrated Electric System (AIES) was used as the basis for all calculations. A set of twelve 2003 load flow conditions as used in AESO's current loss factor calculations was used as the reference power flow cases for all alterative methodologies. The load flow model consists of about 1700 busses, among which 730 have generators, loads or both connected. Bus number 1520 (the 500 kV equivalent of the BC Hydro and WECC system) was designated as the swing bus for the system.

Table 11 presents a summary of the twelve load flow solutions. With the exceptions discussed hereinafter, the summary is based on PSLF Version 13.4 accounting methods. In the load flow data, motor loads are modeled as negative generators; so, total PSLF generation reflects the net component. The contributions of the generation and motor load components have been separated out in the tabulation. The tabulation is similar to the tabulation expected from PSS/E with one exception. PSS/E treats all shunt paths as loads (including transformer no-load losses). PSLF treats transformer shunt paths as magnetizing losses; hence, their contribution to the power balance is included in the 'losses' category.

2.1 Approaches to Loss Factor Calculations
The different methodologies that were evaluated can be categorized into four basic approaches. The four approaches are all based on analyses of loss equations describing the relationship between total transmission system losses and the output of generators connected to the system and modelled in the power flow snapshot of the system operating condition.

2.1.1 Direct Approach
In the direct approach, loss factors are extracted directly from matrix equations describing the relationship between system losses and generation and load at each bus. The equations are examined, and arranged in a form such as the following:

$$\begin{aligned}\text{Losses} = {} & K_1(Pg_1, Pg_2, \cdots Pg_n, Pl_1, Pl_2, \cdots Pl_n)\cdot Pg_1 \\ & + K_2(Pg_1, Pg_2, \cdots Pg_n, Pl_1, Pl_2, \cdots Pl_n)\cdot Pg_2 \\ & + \cdots \\ & + K_n(Pg_1, Pg_2, \cdots Pg_n, Pl_1, Pl_2, \cdots Pl_n)\cdot Pg_n \\ & + K_0\end{aligned} \qquad \text{Equation (1)}$$

where:

Pg_i represents the output of generator at bus 'i' and Pl_i represents the magnitude of the load at bus 'i'. In the direct method, the loss factor for generator 'i' is set to the function:

$$lf_i = K_i(Pg_1, Pg_2, \cdots Pg_n, Pl_1, Pl_2, \cdots Pl_n) \cdot Pg_i \qquad \text{Equation (2)}$$

This function which when evaluated for each generator is multiplied directly by the generator output, providing an indication of the generators contribution to total system losses. The function can therefore be equated to a loss factor.

The term 'K_0' in Equation (1) represents all components of the total system loss that are independent of generation. This component of the losses is not accounted for during the assignment of losses to generation and therefore will represent the contribution of the direct methodology to the shift factor required to balance the assigned loss equation.

2.1.2 Gradient and Gradient by 2 Methods (Marginal Calculations)

In the gradient method, the loss factor of a single generator is determined from its marginal impact on transmission losses. The gradient, equal to the change in system losses for a given change in individual unit generation can be calculated analytically by differentiation of Equation (1) or numerically using tools such as a load flow to make small changes to individual generator output, and monitoring the impact of the change in system losses. The raw loss factor for each generator is set equal to the gradient. The gradient method may over or under assign losses resulting in a requirement for a shift factor to balance the loss equation.

The gradient method provides a very good estimate of the incremental losses caused by each generator. However, as losses are typically a function of the square of the generation, it does not provide a very good indication of contribution of the total output of the generator to the losses. It can be shown analytically that 100% of the losses can be attributed to both generators and loads based on ½ of their individual gradients. However, as the contributions due to loads must be assigned to the generators, the contribution to losses can be expressed as a shift factor to each of the generator loss factors to balance the loss equation.

2.1.3 Incremental Loss Factor Method

The incremental loss factor method as defined in these investigations is similar to the gradient methods, except the change in output of the generator is set equal to the operating output of the generator. The impact on losses can be determined using differences in load flow losses with and without the generator. Alternatively, an approximate estimate of the incremental loss factors can be determined analytically by solving Equation (1), with and without the generator. The methodology can be used to determine the contribution of losses due to a single generator for a single operating condition, but does not take into account any mutual effects say due to generators in the same location. As a result the methodology may under-(or over-)assign losses and again the shift factor is required to balance the loss equation.

2.1.4 Flow Tracking Method

The flow tracking method is based on tracing the power flows in one direction, upstream from the loads towards the generators or downstream from the generators to the loads. The first approach assigns the losses to the generators, and the latter to the loads. As generators pay for losses in the AESO system, the first approach was investigated. Since exactly 100% of the losses of each branch transmission losses are allocated to one or more of the generators in the system, there, is no over-(or under-)allocation of losses with this methodology. The shift factor is theoretically zero with this method. Several generators in the AIES, however, are not required to pay for losses. The contributions of these generators to total system losses are socialized to other generators using a shift factor.

2.2 Calculation of Gradients
For the gradient methods, several treatments of system load and generation are possible when the gradients are calculated. The treatments that were considered are discussed hereinafter.

2.2.1 Present AESO Swing Bus Method
The present AESO loss factor methodology uses a single swing bus method in which one generator is designated as a swing bus and loss factors are calculated for each other generator based on load flow results. The generator loss factor is equal to the change in losses for a small change in output for the generation for which the loss factor is being calculated. By definition, the raw loss factor of the generator at the swing bus is zero.

2.2.2 Area Load Adjustment
In the area load adjustment method, the generator for which the loss factor is being determined is designated as the swing generator, and load is changed at every bus in the area by a constant ratio. For this calculation the 'area' is selected to be the entire Alberta system. Again loss factor is calculated equal to the change in losses for the resultant change in generation at the swing bus.

2.2.3 Partial Differentiation
A third method for calculating gradient-based loss factors is to set the loss factor for each generator equal to the partial derivative of the loss equation with respect to the output of the generator. This is a purely mathematical expression for loss factor and there is an underlying assumption that all other contributions to the loss equation remain constant.

The loss factor for each generator based on Equation (1) would be equal to the 'direct' loss factor (i.e. the function defined by Equation (2)) plus an additional component equal to the partial derivative of the function with respect to the generator output.

2.3 Solution Methods
In the matrix analysis approaches, loss factors are determined directly from matrices describing the relationship between generator power, bus loads and ac system topology.

The matrix analysis includes an approximate (uncorrected) or exact (corrected) loss matrix describing the dependency of losses on both generation and load. In addition, loss factors were determined using the Kron loss matrix equation in which losses are expressed as only a direct function of generation.

3 Methodologies Evaluated

Generator loss factors were determined for each of the methodologies given hereinafter and the results are compared as discussed in Section 0.

3.1 Direct Methodology Using Uncorrected Loss Matrix

In this methodology, the loss factors are determined directly from the coefficients of a system loss matrix.

The system loss matrix is derived from topology and is of the form:

$$\mathbf{R_{uncorr}} = \left(\overline{\mathbf{Y}^{-1}}\right)^{\mathbf{T}} \cdot \mathbf{M^T} \cdot \mathbf{G} \cdot \mathbf{M} \cdot \mathbf{Y}^{-1} \qquad \text{Equation (3)}$$

where:

$\mathbf{Y}$ is the nodal admittance matrix for the system

$\left(\overline{\mathbf{Y}^{-1}}\right)^{\mathbf{T}}$ is the transpose of the conjugate of the inverse of the nodal admittance matrix

$\mathbf{M}$ is the branch incidence matrix

$\mathbf{G}$ is the diagonal matrix of branch conductances.

If '$\mathbf{Y}$' is symmetrical, it can be shown that the matrix '$\mathbf{R}$' is real, and the uncorrected '$\mathbf{R}$' matrix is in effect the real component of the inverse of the nodal admittance matrix $\mathbf{Y}$.

Losses can be calculated directly using the expression

$$\text{Losses} = \left(\overline{\mathbf{I}}\right)^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{I} \qquad \text{Equation (4)}$$

where:

$\mathbf{I}$ is a vector of current injections corresponding to each generator and load bus of the system and $\left(\overline{\mathbf{I}}\right)^{\mathbf{T}}$ is the transpose of the conjugate of the vector of current injections.

To a first approximation, the loss equation using the system loss matrix can be written in the form:

$$\text{Losses} = (\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot (\mathbf{Pg} + \mathbf{Pl}) \qquad \text{Equation (5)}$$

where:

$\mathbf{Pg}$ contains the generator output (p.u.) and $\mathbf{Pl}$ contains the negative values of individual loads (p.u.). Loads are treated as negative generators in this equation.

Since the matrix '$\mathbf{R}$' is symmetrical, the equation can be re-written in the form:

$$\text{Losses} = (\mathbf{Pg} + 2\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{Pg} + \mathbf{Pl}^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{Pl} \qquad \text{Equation (6)}$$

In this expression, losses can be expressed as a function of two components: one component that is independent of generation and another component that is dependent on both load and generation.

The component that is a function of generation is of the form:

$$\mathrm{Losses}_g = \mathbf{LossFactor}^{\mathbf{T}}\mathbf{Pg} \qquad \text{Equation (7)}$$

where:

$$\mathbf{LossFactor}^{\mathbf{T}} = (\mathbf{Pg} + 2\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \qquad \text{Equation (8)}$$

In this methodology, loss factors were calculated **directly** from the above Equation (8).

The loss matrices '**R**' used in this analysis were the 'uncorrected' matrices, based only on system topology.

In this method, the losses that are a function of only the load component are the major contributor to the unassigned losses. There is an additional component due to errors in loss estimation introduced as a result of using an uncorrected loss matrix.

3.2 Direct Methodology Using Uncorrected Loss Matrix

If load flow information (such as bus voltages, angles and generator and load power factors) is available, each individual term of the loss matrix can be 'corrected' by the expression:

$$\zeta_{i,j} = \frac{\cos((\phi_i - \phi_j) - (\sigma_i - \sigma_j))}{v_i \cdot v_j \cdot \cos(\phi_i) \cdot \cos(\phi_j)} \qquad \text{Equation (9)}$$

$$R_{\mathrm{corr}_{i,j}} = R_{\mathrm{uncorr}_{i,j}} \cdot \zeta_{i,j} \qquad \text{Equation (10)}$$

where:

subscripts 'i' and 'j' point to elements of the '**R**' matrix, corresponding to respective buses in the system.

ϕ_i and ϕ_j correspond to the power factor angles at buses 'i' and 'j' respectively.

σ_i and σ_j correspond to the voltage angles at buses 'i' and 'j' respectively.

and v_i and v_j correspond to the magnitudes of the voltages at buses 'i' and 'j' respectively.

With these corrections, Equation (5) above becomes an exact numerical expression of losses.

In this set of calculations the corrected loss matrices were used. Corrections were based on bus voltages, bus angles, and generator and load power factors obtained from the base-case load flow solutions.

With the corrected loss matrix, Equation (5) above gives exactly the same numerical value for total system losses as the load flow.

3.3 Swing Bus Methodology Using Uncorrected Loss Matrix

Equation (5) above can be used to determine the change in losses for a small change in swing bus and loss factor bus generation.

It can be shown that if the loads are unchanged, the change in total system losses due to change in generation is approximately given by:

$$\Delta\text{Losses} = 2(\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{\Delta Pg} \qquad \text{Equation (10)}$$

It is also known that since load is constant, the change in losses is also equal to the sum of the changes in generation, i.e.:

$$\Delta\text{Losses} = \sum_{i} \Delta\text{Pg}_i \qquad \text{Equation (11)}$$

If generation is assumed to be constant at all but the swing bus and the bus at which the loss factor is being calculated, the above equations reduce to two equations with three unknowns: ΔLosses, ΔPg_1 (the change in generation at the bus for which the loss factor is being calculated), and ΔPg_s(the change in generation at the swing bus).

The simultaneous equations can be combined to calculate the ratio:

$$\frac{\Delta\text{Losses}}{\Delta\text{Pg}_1}$$

This is effectively the definition of raw loss factors used in the present AESO loss factor methodology.

For these calculations, the bus 493 (Clover Bar) was used as the swing bus for the calculations. This is consistent with the present AESO swing bus loss factor methodology.

3.4 Swing Bus Methodology Using Corrected Loss Matrix

The calculation discussed in 0 above was repeated using the corrected loss matrix. In using the corrected loss matrix for this calculation, the set of assumptions change. For the uncorrected loss matrix calculations, it is mathematically exact to assume that the '**R**' matrix does not change with small changes in load, as the uncorrected '**R**' matrix is a function of only system topology. Assuming the corrected '**R**' matrix to be constant implies that all of the corrections made to the '**R**' matrix are also independent of small changes in generation.

In practice, a small change in generator power output is not likely to significantly alter bus voltages. Load power factors will remain constant, in the same manner as a load flow solution. Generator power factors however are likely to change particularly at the generator where the loss factor is being evaluated and the swing bus. Assuming a constant power factor could lead to undesired consequences.

Any generator operating with a low power factor (for example units connected primarily for var support) would be very susceptible to high loss factor calculations. Assuming the power factor to be constant implies that with every increment in generator output there is a corresponding increase in generator var output. As actual transmission losses are not only a function of MW but also Mvar, the small change in generator output could have a significant impact on total system losses associated with the assumption of a constant '**R**' matrix. The net result is that low power factor generators could be assessed excessively large loss factor penalties or credits.

A second undesirable effect of this assumption is that some generators could be penalized in terms of increased loss factors for supplying vars to the system under conditions when vars are needed on the system. It is also conceivable that some generators and associated loads could receive credits for taking vars from the system under var shortage conditions.

One method of circumventing this issue is to treat all var injections, from both loads and generators as equivalent constant admittance shunt devices. The nodal admittance matrix must be adjusted to include this effect, before the '**R**' matrix is established.

The implication of this treatment of load and generator vars is that the load and generator var injections are treated as being constant. Since bus voltages are assumed to be constant, the vars generated by the equivalent shunt devices are also constant. This is again a reasonable approximation for small changes in generator output.

If the power market evolves to include equivalent var loss factors for both generators and loads, these assumptions would need to be revisited.

3.5 Area Load Methodology Using Uncorrected Loss Matrix

Equation (5) above also can be used to determine the change in losses for a small change in swing bus generation and total system load. If all of the loads in the system are increased by a small percentage (say δ), the total change in system losses can be approximated by the following expression:

$$\Delta \text{Losses} = 2(\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{\Delta Pg} + \delta \cdot 2(\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{Pl} \qquad \text{Equation (12)}$$

$$\Delta \text{Losses} = \sum_i \Delta \text{Pg}_i + \delta \cdot \sum_i \text{Pl}_i \qquad \text{Equation (13)}$$

If only the generation at the loss factor bus changes, then again the above equations can be reduced to two simultaneous equations with three unknowns (ΔLosses, ΔPg_1, δ)

The simultaneous equations can be combined to again calculate the ratio:

$$\frac{\Delta \text{Losses}}{\Delta \text{Pg}_1}$$

For this methodology, the generator for which the loss factor is calculated effectively becomes the swing machine for the system. Hence the loss factors calculated are independent of an arbitrary selection of a swing bus in the system.

3.6 Area Load Methodology Using Corrected Loss Matrix

The calculation method discussed in 0 above was repeated using the corrected loss matrix. This method is again subject to the limitations introduced by the assumptions regarding the constant '**R**' matrix discussed in Section 0. Generator and load vars are treated as equivalent shunt devices and hence are indirectly assumed to be constant, by the assumption of constant voltages.

As the main function of generator loss factors is to define the relationship between generator power output and transmission losses, it is reasonable to assume that the variation in system load is related only to the active power component, i.e., the change in load vars is zero. The assumption of constant load vars in this corrected '**R**' matrix methodology is therefore reasonable.

3.7 Gradient Methodology Using Uncorrected Loss Matrix

The partial derivative of equation 5 above with respect to individual generator output can be determined for each generator as follows:

$$\frac{\partial \mathrm{Losses}}{\partial \mathrm{Pg}_i} = 2 \cdot (\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{S(i)} \qquad \text{Equation (14)}$$

where $\mathbf{S(i)}$ is a vector in which the i^{th} element is 1.0 and all other elements are zero.

A vector of all the gradients is simply:

$$\left(\frac{\partial \mathbf{Losses}}{\partial \mathbf{Pg}}\right)^{\mathrm{T}} = 2 \cdot (\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \qquad \text{Equation (15)}$$

The above can be used to allocate losses to generators by multiplying each individual gradient by the generator output.

3.8 Gradient Methodology Using Corrected Loss Matrix

The calculation discussed in 0 above can be repeated using the corrected loss matrix. Again the loss factors are dependent on the assumption of a constant '**R**' matrix. This is a mathematically exact assumption, however the impacts of the assumption are the same as discussed in Section 0. Load and generator var outputs must be assumed to be constant and be embedded in the '**R**' matrix to avoid unrealistic penalties and credits for vars supplied or absorbed from the system.

3.9 Gradient by 2 Methodology Using Uncorrected Loss Matrix

If Equation (15) above is expanded to include all buses for which generation or load is included, it can be combined with Equation (2) to give:

$$\text{Losses} = \tfrac{1}{2}\left(\frac{\partial \mathbf{Losses}}{\partial \mathbf{Pg}}\right)^{\mathbf{T}} \cdot (\mathbf{Pg} + \mathbf{Pl}) \quad \text{Equation (16)}$$

I.e. the total losses of the system can be allocated to load and generation buses based on ½ the gradient calculated for each generator and load bus. The component that is due to generation can be determined from:

$$\text{Losses}_g = \tfrac{1}{2}\left(\frac{\partial \mathbf{Losses}}{\partial \mathbf{Pg}}\right)^{\mathbf{T}} \cdot \mathbf{Pg} \qquad \text{Equation (17)}$$

and the component of the losses due to load is given by:

$$\text{Losses}_l = \tfrac{1}{2}\left(\frac{\partial \mathbf{Losses}}{\partial \mathbf{Pg}}\right)^{\mathbf{T}} \cdot \mathbf{Pl} \qquad \text{Equation (18)}$$

The term $\tfrac{1}{2}\left(\frac{\partial \mathbf{Losses}}{\partial \mathbf{Pg}}\right)$ in Equation (17) can be considered to be a vector of generator raw loss factors and the term 'Losses_l' of Equation (18) can be considered to be unassigned losses that are due to loads and which must be factored into the loss balance equation using a shift factor.

One advantage of this methodology is that there is a quantitative explanation of all components of the losses.

3.10 Gradient by 2 Methodology Using Corrected Loss Matrix

The calculation discussed in Section 0 above can be repeated using the corrected loss matrix. Again the assumptions regarding the constant '**R**' matrix discussed herein are applicable.

3.11 50% Area Load Methodology Using Uncorrected Loss Matrix

It will be shown that the losses assigned by the area load adjustment methodology are almost twice the actual losses. The loss factors calculated using area load adjustment will be reduced by 50% to determine the average losses and unassigned losses and the shift factor will be recalculated. Please refer to Appendix A

3.12 50% Area Load Methodology Using Corrected Loss Matrix

The loss factors calculated using area load adjustment and the corrected loss matrix will also be reduced by 50% to determine the average losses and unassigned losses and the shift factor will be recalculated. It is shown in Appendix A that loss factors calculated in this manner will account for almost all of the system losses resulting in a shift factor in the order of less than 0.15%. It will be shown numerically in Section 0 that the unassigned losses and resultant shift factor for this methodology are essentially zero.

Again the assumptions regarding the constant '**R**' matrix discussed herein are applicable.

3.13 Kron Loss Matrix Using Direct Methodology

An alternative matrix expression of losses used for optimal power flow solutions is the Kron loss matrix formula.

The equation is of the form:

$$\text{Losses} = \mathbf{Pg}^{\mathbf{T}} \cdot \mathbf{B02} \cdot \mathbf{Pg} + \mathbf{B01}^{\mathbf{T}} \cdot \mathbf{Pg} + \text{B00} \quad \text{Equation (19)}$$

In the above equation, '$\mathbf{Pg}$' is a vector housing the magnitude of the real output of the generators, $\mathbf{B02}$ is a matrix, $\mathbf{B01}$ is a vector and B00 is a simple scalar.

The loss equation above can be rewritten in the form:

$$\text{Losses} = \left(\mathbf{Pg}^{\mathbf{T}} \cdot \mathbf{B02} + \mathbf{B01}^{\mathbf{T}}\right) \cdot \mathbf{Pg} + \text{B00} \quad \text{Equation (20)}$$

The bracketed term $\left(\mathbf{Pg}^{\mathbf{T}} \cdot \mathbf{B02} + \mathbf{B01}^{\mathbf{T}}\right)$ can be considered to be a transposed vector of raw loss factors as it allocates all but the component 'B00' of the losses to the generators. The term 'B00' represents an unallocated loss component that will contribute to the shift factor.

3.14 Kron Loss Matrix Using Swing Bus Methodology

The Kron loss equation can be rearranged in a similar fashion to the loss matrix equation to determine loss factors based on the existing swing bus methodology.

$$\Delta\text{Losses} = 2 \cdot \left(\mathbf{Pg}^{\mathbf{T}} \cdot \mathbf{B02} + \mathbf{B01}^{\mathbf{T}}\right) \cdot \Delta\mathbf{Pg} \quad \text{Equation (21)}$$

It is also known that the change in losses is equal to the sum of the change in losses in all generators, i.e.:

$$\Delta\text{Losses} = \sum_{j} \Delta\text{Pg}_j \quad \text{Equation (22)}$$

If generation is assumed to be constant at all but the swing bus and loss factor bus, the above equations reduce to two equations with three unknowns, namely: ΔLosses, ΔPg_1 (the change in generation at the bus for which the loss factor is being calculated), and ΔPg_s(the change in generation at the swing bus).

The simultaneous equations can be combined to calculate the ratio:

$$\frac{\Delta \text{Losses}}{\Delta \text{Pg}_1} \qquad \text{Equation (23)}$$

Similar to the corrected loss matrix methods discussed above, this method assumes that the coefficients '**B02**', **'B01'** and 'B00' are constant. While the coefficients are not as straight forward as the loss matrix '**R**' matrix calculations, imbedded in the formulation of the coefficients are corrections for bus voltages, power factors and power angles. As a result, the implications of the assumption of constant coefficients in this methodology are the same as the assumption of constant '**R**' matrix in the corrected loss matrix methodologies.

3.15 Kron Loss Matrix Using Gradient by 2 Method

The partial derivative of Equation (19) above can be determined for each generator as follows:

$$\frac{\partial \text{Losses}}{\partial \text{Pg}_i} = \left(2 \cdot \mathbf{Pg}^{\mathbf{T}} \cdot \mathbf{B02} + \mathbf{B01}^{\mathbf{T}}\right) \cdot \mathbf{S(i)} \qquad \text{Equation (24)}$$

where '**S(i)**' again is a vector in which the i^{th} element is 1.0 and all other elements are zero.

The vector

$$\mathbf{G}^{\mathbf{T}} = 2 \cdot \mathbf{Pg}^{\mathbf{T}} \cdot \mathbf{B02} + \mathbf{B01}^{\mathbf{T}} \qquad \text{Equation (25)}$$

therefore contains all of the gradients calculated for each generator.
If the gradient is dominated by the first term in Equation (25), the loss equation can be re-written to:

$$\text{Losses} = \tfrac{1}{2} \cdot \mathbf{G}^{\mathbf{T}} \cdot \mathbf{Pg} + \text{B00} + \varepsilon \qquad \text{Equation (26)}$$

where the term 'ε' represents the error introduced by the approximation by ignoring the B01 component and which must be compensated for in the shift factor along with the B00 term.

Again the coefficients '**B02**', '**B01**' and 'B00' are all assumed to be constant in this methodology. Similar to the loss matrix methodologies discussed in Section 0 and 0, this is mathematically correct but the implications are the same as discussed in Section 0 above.

3.16 Incremental Loss Factor Methodology

The incremental loss factor methodology requires the calculation of the change in losses as the output of a generator is adjusted from no load to its loading as represented in the loadflow. In equations 12 and 13 above, if the change in generation 'ΔPg_1' is known, the change in losses '$\Delta Losses$' and the load adjustment factor 'δ' can be determined by solving the two simultaneous equations. The loss factor is set to the numerical value of '$\Delta Losses$' divided by 'ΔPg_1'. At generator buses where the output is zero, the amount of power reduction is set equal to 0.00001 MW (i.e. the marginal loss factor).

Similar to the rest of the analytical methods discussed above, an assumption is made that the '**R**' loss matrix is unchanged as a result of the change in generation and load.

One of the known limitations of the methodology is its inability to handle TMR situations. Under 'transmission must run' load flow conditions, shut down of a TMR generator (or reduction of power to zero) could result in load flow convergence failure. Although the analytical implementation of the ILF methodology is not subject to convergence issues, the assumptions made would deviate significantly from the practical situation and a significant reduction in accuracy would result.

A second known limitation of this methodology is that generators of different capacity, located at or close to the same bus will be assigned different loss factors. This is not in accordance with the regulations and would require 'special' treatment of nearby generators to meet the regulation requirements. While a mathematical 'special' treatment is possible for these generators, the extent of the definition of 'nearby' will become an issue with this methodology.

3.17 Flow Tracking Methodology

The flow tracking methodology requires that the losses be known for every branch in the system. Each transmission branch loss is assigned to one of the adjacent buses in the direction of tracking; then redistributed among lines proportionally to the flows, again in the direction of tracking. The process is recursive and eventually ends up at the generator buses with the losses assigned to them. Loss factors are then determined based on the assigned losses at each bus.

Several features and known limitations of the methodology are:

Losses can only be assigned to either generators or loads, not both at the same time. Any attempt to mix the assignment of losses to both generators and loads would lead to a major change of the algorithm and would require an arbitrary decision on breaking points in the system where the algorithm basis would be switched. As such in the Alberta situation where generators are responsible for losses, any losses associated with exports or DOS loads could not be handled with this algorithm.

Loss factor credits are not possible. All loss factors are positive, implying a smaller permitted range of loss factors (after compression) and hence less locational-based generating signals.

All load buses are assigned a zero loss factor. This implies that all buses without generation are assigned a loss factor of zero.

All generators at buses where load exceeds generation will be assigned a loss factor of zero. This also applies to 'no-loss' areas where load exceeds generation. All generators in such an area would have a loss factor of zero. As a result, the level of encouragement provided for new generation is independent of the magnitude of potential benefit.

The methodology fails when situations arise where a generator is small but the var flow in adjacent circuits are large. Such would be the case for units connected primarily for voltage control or for small units connected close to buses with large capacitors. A solution could be to ignore loss factors for small units, but this would require some formula to decide under which situation a unit should be ignored. This will be more complicated than a simple MW criterion as Mvar to MW ratio comes into play.

4. Comparison of Methodologies

Loss factors were calculated for every generator in the Alberta system for each of the twelve 2003 base-case load flows and for each of the 17 methodologies discussed in Section 0 above. The results of these calculations are summarized herein.

4.1 Required Shift Factor

Table 12 and Table 13 summarize the shift factors associated with each load flow and each methodology. The magnitude of the shift factor is a measure of the ability of each methodology to allocate total system losses on a mathematically defined basis. In this context, shift factor is defined to be the correction that must be made to the loss factor for each individual generator to account for all of the unassigned power (MW) losses in the system. A positive shift factor implies that the methodology would result in an under-assignment of total system losses. I.e., the loss factors of each generator must be increased by the shift factor to recover all of the power flow losses. A negative shift factor implies an over-assignment of losses.

The column "Average Loss Factor" is the ratio of losses to total generation as calculated using a load flow program.

The seasonal average shift factors are simply the average of the shift factors for the three load flows of each season. The annual average shift factor is the average of the four seasonal shift factors (equivalent to the average of the shift factors for all 12 load flows). The average shift factors have no physical interpretation, but are useful for comparing the methodologies.

The shift factors shown in Table 12 and Table 13 are the same. In Table 12, the largest and smallest magnitude shift factors encountered for each methodology, for each power flow, are highlighted. In Table 13 the shift factors for each load flow are compared. The largest and smallest magnitude shift factors encountered for each methodology on a load flow basis are highlighted.

Table 12 indicates that there is no apparent correlation between shift factors and load flow or season. For example, the largest shift factor does not always occur for a specific season or load flow condition, independent of methodology. For some methodologies the largest shift factor occurs under winter peak conditions but for others the smallest shift factor occurs for that load flow condition.

Table 13 however does start to indicate a trend in results. The 50% area load adjustment methodologies (both corrected and uncorrected matrices) account for all of the smallest shift factors calculated. The largest shift factors occur with the following methodologies:

uncorrected R matrix, area load adjustment
corrected R matrix, Direct methodology
Kron Matrix, Swing bus methodology

The corrected and uncorrected loss matrix swing bus methodologies require similar shift factors. Both under-allocate losses, and both require shift factors similar in magnitude to the current AESO swing bus methodology.

The corrected and uncorrected loss matrix area load adjustments again require similar shift factors. Both over-allocate losses. In fact, both methods over-allocate by an amount that is almost equal to the average loss factor, particularly for the corrected loss matrix methodology.

If the loss factors computed with this method are reduced by a factor of 2, resulting in loss factors that are 50% of the area load adjustment methodology, the required shift factor as indicated above is extremely small.

The shift factors required for the uncorrected and corrected loss matrix direct methodologies are not similar in magnitude. This indicates that the methodology is extremely sensitive to assumptions made in the creation of the loss matrix. Both approaches under-assign losses but the shift factors required for the corrected matrix methodology are actually greater than the average system loss factor implying that the total losses accounted for by the methodology are negative.

Similar to the load area adjustment methodology, the loss matrix gradient method significantly over-assigns losses. The corresponding methodology with ½ gradients under-assigns losses, but in this case, the shift factor calculated using the corrected loss matrix is actually greater that the shift factor calculated using an uncorrected matrix. In the corrected matrix, the shift factor is due entirely to the contribution of the system loads to the losses. In the uncorrected method, inaccuracies introduced by the uncorrected loss matrix tend to counteract the effects of the loads. This would not occur if system voltage profiles were lower.

The direct and gradient by 2 Kron matrix based methodologies slightly under-assign losses with the gradient by 2 methodology requiring the lowest shift factor. The Kron matrix swing bus methodology shows less consistent results between load flows.

4.2 Range of Loss Factors

The Alberta Department of Energy has indicated that all 'normalized' loss factors must be no greater than twice the average system loss factor and no less than the negative value of the average system loss factor

The range of loss factors after application of the shift factors described in Section 0 provides an indication of the extent that loss factors calculated using each methodology would exceed the Department's requirements. Table 14 summarizes the variations in loss factors that could be expected and provides an indication of the degree of ultimate loss factor correction that eventually would have to be applied.

For methodologies (such as the incremental loss factor methodology) with a relatively large range in loss factors (37%) and a large number of generators exceeding the criteria (78), the compression algorithm proposed in Part 3 of the report would not be satisfactory. The majority of the units would be either at maximum charge or maximum credit and the locational-based incentives required by the board would be lost. To achieve a distribution of loss factors closer to the intent of compression, other algorithms such as the linear compression algorithm would be required, reducing the locational-based signals of those generators originally within the limits.

In the table, the "maximum loss factor" is the largest adjusted seasonal loss factor (12 case average) based on individual generators. "Minimum loss factor" is the smallest (or largest negative) value and "range of loss factors" is the difference between the two extremes.

The table also indicates the number of generators with loss factors greater than the criteria and the number of generators with loss factors less than the criteria along with the total. Although the loss factors on which the table is based have been adjusted to take into account and balance all of the power flow losses, an additional correction would be required to take into account differences between load flow losses and forecast generator volumes and losses. The next level of correction will shift the range and as a result, the number of generators with loss factors greater than the maximum permitted may change (say increase), but the number of generators with loss factors less than criteria will also change (i.e. decrease) but the change in total number of generators exceeding the criteria should not be significant.

The Kron matrix direct methodology has the lowest range of loss factors and as a result also has the least number of loss factors that exceed the criteria. The uncorrected loss matrix swing-bus methodology has the largest range and consequently the largest number of generators (86) exceeding the criteria.

4.3 Seasonal Volatility

The Alberta Department of Energy has also indicated that each generator will be assigned a single loss factor. This loss factor will represent the contribution of the generator to losses on an annual basis (at minimum). As the loss factors will be based on some average (weighted or un-weighted) of loss factors calculated using load flows as a starting point, the seasonal volatility of the loss factor becomes an indicator of the degree of accuracy that can be expected when assigning energy based loss factors.

Table 14 also indicates the seasonal volatility of loss factors for each methodology. Volatility is expressed as the largest range in individual generator loss factors over each of the four seasons.

Loss factors calculated using the Kron matrix direct and gradient by 2 methodologies are least sensitive to the variations introduced by the four seasons. This is followed closely by the 50%

area load adjustment methodologies and the loss matrix gradient by 2 methods. The range in seasonal volatility for these six methods is from 4.01 to 5.1%.

The flow-tracking methodology has by far the poorest (largest) seasonal volatility at 78.73%. The 'R' loss matrix swing bus methodologies are next with seasonal volatilities of 11.45% and 11.37% for the uncorrected and corrected 'R'-matrix methodologies respectively.

4.4 Ranking of Alternative Methodologies.

Each of the methodologies has certain advantages and disadvantages. To quantify the overall assessment of the methodologies, a ranking has been determined for each of the metrics.

The first metric assessed was the load flow adjustment shift factor. Table 13 indicated that the magnitude of shift factor was dependent on not only the methodology but also the individual load flow condition and the season. To assess this metric, the methodologies were ranked for each load flow condition from 1 to 17, depending on the magnitude of load flow shift factor as shown in Table 15. The methodologies were also ranked in terms of the seasonal and annual loss factors from 1 to 17. A ranking of 1 indicates the most desirable while a ranking of 17 is least desirable.

A weighted average of each of the individual rankings was determined for each methodology. The weightings assigned were:

Individual load flows	1/36
Individual Seasons	3/36
Annual Shift Factor	12/36

The weightings effectively give equal weight (1/3) to all of the load flows, all of the seasons and the annual shift factor.

Table 15 indicates that the methodology with the lowest ranking or minimum overall shift factor is the corrected loss matrix, 50% area load adjustment methodology. The methodology with the highest weighted average is the loss matrix direct methodology. The methodologies have been ranked from 1 to 17 based on the weighted average of the individual ranking as shown in the table.

The methodologies have also been ranked from 1 to 17 based on each of the other metrics discussed above. These are:

The number of generators that exceed the loss factor limits
The range of loss factors
Seasonal Volatility

A fifth metric also considered was the dependency of the methodology on selection of swing bus. A problem associated with those methodologies that are dependent on the selection of swing bus for the system is actually designating the appropriate swing bus. The most appropriate swing bus may need to change with changes in topology and system loading conditions. Those methodologies with no dependence on swing bus selection were assigned a rank of 1 (all tied for 1st place). Those methodologies where there is a dependence on swing bus selection were assigned a ranking of 17 (tied for last place).

Each of the metric rankings were assigned an equal weighting and a weighted sum factoring all of the metrics was determined. The methodology for ranking of alternatives is shown in Table 16. The ranking is based on the weighted sum of the individual rankings.

Based on this assessment method, both loss matrix 50% area load adjustment methodologies rank in the top two, with the corrected loss matrix method on top followed by the uncorrected loss matrix method.

The best (lowest) ranking of methodologies based on the Kron matrix formula is the direct methodology in overall position number 5. The flow-tracking approach ranked 7th while the ranking of the incremental loss factor methodology was 10th overall. The loss matrix swing bus methodologies (close to the current methodology) are ranked last.

As the methodologies can be separated into two distinct groups, namely those based on corrected matrices and those based on uncorrected matrices, the ranking process described above was repeated for each group. The comparable rankings are shown in Table 17 and Table 18.

The 50% area load adjustment methodology remains at the top in both categories. The Kron loss formula based methods improve to positions 2 and 4 in the corrected matrix grouping with the direct methodology in position 2. The swing bus methodology remains in last place in both groupings.

4.5 Qualitative Assessments

4.5.1 Change in Relative Order of Loss Factors

A qualitative assessment was made on selected methodologies relating to the possible degree of acceptability of the methodology to stakeholders. Figure 11 compares the relative position in terms of loss factors of the average loss factor for each of the load flow areas. The order of the area was selected based on the highest to lowest average loss factors for the 50% area load adjustment methodology. The plot designated 'Rmat_Ald50' (50% area load adjustment methodology) is therefore a straight line. With the exception of load flow areas 55 and 17 where the ranking of the average loss factors is swapped, the ranking of the 50% area load adjustment methodology is the same as the ranking of the 'RMat_Swg_Cor' (corrected 'R' loss matrix, swing bus methodology). The latter methodology is similar to the current methodology. While the magnitudes of the loss factors will be different between the two methodologies, there will be few 'winners' or 'losers' in terms of relative order of the loss factors.

The loss factors for the 'RMat_Der2_Cor' (corrected 'R' loss matrix 50% gradient methodology) are ranked in the same order as the 50% area load adjustment methodology. Loss factors for 'ILF' (incremental loss factor methodology) follow a similar overall trend to the current methodology, however there are more differences in ranking and as a result more 'winners' and 'losers' in terms of relative competitiveness from loss charge considerations.

The flow tracking methodology would result in a significant shift in the distribution of charges and credits. Generators in areas that presently have similar loss factors could end up with vastly different loss factors ranging in some areas from maximum credits to maximum charges.

While the objective of the methodology investigation was not to maintain a 'status quo', all other factors being equal, 50% area load adjustment and 50% gradient methodologies, would be preferred to the other methods compared.

4.5.2 Transmission Must Run Capability

As the incremental loss factor methodology cannot accurately handle TMR generating conditions, a 'special' treatment of these generators would be required. The regulations require that all generators at the same bus have the same loss factor. This is not an inherent feature of the incremental loss factor methodology and again special treatment of generators within the same area may be required to achieve this objective. While a requirement for 'special' treatment has not been factored into the quantitative given assessment above, all other factors being equal, methodologies where 'special' treatment is not required would be preferable to the incremental loss factor methodology.

4.5.3 Var Flow Issues

Complications associated with large generator var flow have been taken care of in the 'R' loss matrix and Kron Matrix methodologies by converting all var load and generator var outputs to equivalent shunt devices before determining the loss factors.

As indicated above, the flow tracking methodology would require 'special' treatment for small generators connected to branches with large var flows. Similar to the incremental loss factor methodology above, all other factors being equal, methodologies where 'special' treatment is not required would be preferable to the flow tracking methodology.

4.5.4 Locational Based Signals

The quantitative evaluation of alternative methodologies took into account loss factors outside of the permitted loss factor range, but did not factor in the loss of locational-based signals for methodologies where the loss factor range is less than the permitted range. With the exception of the flow tracking methodology loss factor compression will force all generator loss factors to be within the permitted loss factor range, and the range is such that the locational-based generating signal is maintained.

With the flow tracking methodology, as there are no credits in the raw loss factors, compression will apply only to charges and the strength of the resultant locational-based signal will be about 2/3 of the strength of the signals created by the other methodologies. All other factors being equal, methodologies where the locational-based signal is stronger would be preferable to the flow tracking methodology.

5 Recommendation

Based on the rankings of alternatives, it is clear that the loss matrix 50% area load adjustment methodology is the best approach to allocating losses to generators. The methodology results in a small load flow shift factor. Generator loss factors are independent of the selection of the swing bus for the system. I.e. when the loss factor is calculated for each generator, the bus to which the generator is connected must become the swing bus for the system. The number of generators that are likely to drive loss factor compression is small (in the order of 12) and the extent of compression required is low with a requirement to reduce the loss factor range from about 18.5% to three times the average loss factor or about 15%.

One of the other requirements of the Alberta Department of Energy is that with the chosen methodology, loss factors of nearby (electrical) generators be similar.

Loss factors were calculated for each generator in each of the load flow areas. The results are given in Table 19 for the corrected loss matrix and Table 20 for the uncorrected loss matrix, 50% area load adjustment methodologies. In Table 19, the variation in adjusted loss factors varies from as low as 0.05% in load flow area 43 (Sheerness) to as high as 7.03% in load flow area 97 (designated as "IPP site"). The variation in area 40 (Lake Wabamun accounting for the majority of the Alberta system generation) is only 0.76%.

Although there is a slight shift in the loss factors within each area when calculated with the uncorrected loss matrix, the range remains about the same, in particular in area 40 where the range of loss factor variation remains low at 1.31%.

A comparison of the average loss factors for each of the load flow areas and for both the corrected and un-corrected loss matrices is given in Figure 10. The pattern evident in the average loss factors for each load flow area for the uncorrected matrix methodology is similar to the corresponding pattern with the corrected matrix methodology. However, the loss factors (both penalties and credits) are sufficiently different so as to limit the usefulness of the uncorrected matrix methodology.

The uncorrected matrix methodology has advantages in terms of transparency. These methodologies eliminate the variation introduced into the loss factor calculation as a result of load flow solution.

For the existing methodology, loss factors for all new generators are based on information deemed to be confidential by the generators. This information is embedded in the load flows and as a result, the load flows themselves have also been deemed to be confidential. If the loss factor calculations were based on an uncorrected loss matrix, the calculation would be dependent only on system topology and assumed distribution of generation and loads. System topology and data is openly available through TASMO. The distribution of loads is not considered confidential and the stacking order for generation is public information. The only unavailable quantity would be the amount of generation assumed for each entry in the stacking order as this information was considered to be confidential. It should be possible, however, to establish a reasonable estimate of the generation distribution based on historical system performance and posted representative system load flows.

If an approach to loss factor calculations is adopted that is based on historical utilization of the transmission system by each generator, the confidentiality issue may disappear, and all aspects of the loss factor calculations could become public.

In this case, the value of the uncorrected matrix methodologies diminishes. The corrected matrix methodology should be adopted because of its more accurate distribution of load flow losses.

The recommended methodology therefore for determining load flow based ‘raw’ loss factors for generators is the corrected loss matrix, 50 % area load adjustment methodology.

Table 11 Load Flow Solution Summary

	WnPk	WnMd	WnLw	SpPk	SpMd	SpLw	SmPk	SmMd	SmLw	FlPk	FlMd	FlLw
Total Generation	**8456.8**	**7845.7**	**7548.6**	**7978.7**	**7554.2**	**7297.3**	**8269.2**	**7594.3**	**7331.2**	**8390.3**	**7737.9**	**7459.0**
Generation	8423.8	7812.7	7515.6	7945.7	7521.2	7264.3	8236.2	7561.3	7298.2	8357.3	7704.9	7426.0
Negative loads	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Total Imports	**258.9**	**-8.3**	**-604.1**	**98.0**	**-70.3**	**-673.3**	**94.6**	**-33.1**	**-706.8**	**433.4**	**3.6**	**-619.1**
SPC Imports	100.0	-0.1	-75.0	100.0	0.0	-75.0	100.0	-0.1	-75.0	100.0	0.0	-75.0
BC Imports	158.9	-8.2	-529.1	-2.0	-70.3	-598.3	-5.4	-33.0	-631.8	333.4	3.6	-544.1
Total Loads	**8345.3**	**7473.8**	**6536.0**	**7718.0**	**7144.5**	**6236.6**	**8020.0**	**7229.3**	**6236.2**	**8468.4**	**7393.4**	**6449.7**
Constant P Loads	8043.6	7172.4	6234.4	7453.2	6879.6	5971.6	7725.8	6935.1	5942.0	8173.4	7098.4	6154.7
Motor Loads	276.2	276.2	276.2	239.4	239.4	239.4	294.2	294.2	294.2	295.0	295.0	295.0
Shunts	25.5	25.2	25.3	25.4	25.4	25.6	0.0	0.0	0.0	0.0	0.0	0.0
Load Flow Losses	**370.5**	**363.5**	**408.5**	**358.7**	**339.5**	**387.4**	**343.8**	**331.9**	**388.2**	**355.3**	**348.1**	**390.2**
Generation + imports less loads	370.5	363.5	408.5	358.7	339.5	387.4	343.8	331.9	388.2	355.3	348.1	390.2
Mismatch	**0.000**	**0.001**	**0.039**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

Table 12 Load Flow Shift Factors Required For Each Methodology (Part "a")

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology	Gradient Methodology	Gradient Methodology
WnPk	4.77%	2.07%	1.43%	-4.79%	-4.57%	-0.01%	0.10%	2.07%	7.87%	-2.84%	-0.70%
WnMd	5.16%	3.75%	2.88%	-5.25%	-4.99%	-0.04%	0.09%	1.73%	7.47%	-3.62%	-1.84%
WnLw	6.42%	4.19%	3.99%	-7.82%	-6.37%	-0.70%	0.02%	0.86%	6.58%	-6.77%	-5.72%
SpPk	5.01%	2.06%	1.48%	-4.93%	-4.84%	0.04%	0.09%	1.91%	7.87%	-3.19%	-1.67%
SpMd	5.05%	3.30%	2.43%	-5.09%	-4.90%	-0.02%	0.07%	1.63%	8.21%	-3.66%	-2.16%
SpLw	6.41%	3.38%	3.37%	-7.66%	-6.47%	-0.62%	-0.03%	0.93%	6.85%	-6.87%	-7.16%
SmPk	4.32%	1.69%	1.20%	-4.80%	-4.15%	-0.24%	0.08%	1.79%	6.67%	-2.95%	-0.43%
SmMd	4.55%	3.44%	2.67%	-5.12%	-4.42%	-0.29%	0.06%	1.34%	6.43%	-3.66%	-1.85%
SmLw	6.03%	3.04%	3.43%	-8.02%	-6.05%	-0.99%	-0.01%	0.57%	5.93%	-7.14%	-6.41%
FlPk	4.22%	1.03%	0.58%	-4.50%	-4.06%	-0.14%	0.08%	0.57%	6.26%	-2.61%	-0.51%
FlMd	4.65%	3.70%	2.93%	-5.36%	-4.53%	-0.35%	0.06%	1.30%	5.64%	-3.81%	-2.09%
FlLw	5.86%	3.24%	3.42%	-7.70%	-5.86%	-0.92%	0.00%	0.74%	5.55%	-6.77%	-5.73%
Winter Average		3.34%	2.77%	-5.95%	-5.31%	-0.25%	0.07%	1.55%	7.31%	-4.41%	-2.75%
Spring Average		2.91%	2.43%	-5.90%	-5.40%	-0.20%	0.04%	1.49%	7.64%	-4.57%	-3.66%
Summer Average		2.72%	2.43%	-5.98%	-4.88%	-0.51%	0.04%	1.23%	6.34%	-4.58%	-2.90%
Fall Average		2.66%	2.31%	-5.85%	-4.82%	-0.47%	0.05%	0.87%	5.82%	-4.40%	-2.78%
Annual Average		2.91%	2.48%	-5.92%	-5.10%	-0.36%	0.05%	1.29%	6.78%	-4.49%	-3.02%

		Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix	Corrected R-matrix	Branch Loss Matrix
Loading Condition	Average Loss Factor	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology	ILF Methodology	Flow Tracking
WnPk	4.77%	0.96%	2.03%	1.19%	-11.95%	0.65%	-2.50%	0.51%
WnMd	5.16%	0.77%	1.66%	1.28%	-7.63%	0.68%	-2.89%	0.50%
WnLw	6.42%	-0.18%	0.35%	1.82%	2.50%	0.40%	-3.68%	0.55%
SpPk	5.01%	0.91%	1.67%	1.26%	-9.02%	0.70%	-2.68%	0.56%
SpMd	5.05%	0.69%	1.45%	1.27%	-5.68%	0.75%	-2.83%	0.50%
SpLw	6.41%	-0.23%	-0.37%	1.98%	9.49%	0.38%	-3.57%	0.54%
SmPk	4.32%	0.68%	1.94%	0.91%	-11.19%	0.49%	-2.13%	0.20%
SmMd	4.55%	0.44%	1.35%	0.90%	-5.28%	0.47%	-2.45%	0.18%
SmLw	6.03%	-0.55%	-0.19%	1.72%	5.81%	0.06%	-3.08%	0.19%
FlPk	4.22%	0.81%	1.86%	0.86%	-12.00%	0.46%	-1.93%	0.20%
FlMd	4.65%	0.42%	1.28%	0.89%	-5.52%	0.39%	-2.51%	0.17%
FlLw	5.86%	-0.45%	0.07%	1.47%	3.33%	0.11%	-3.18%	0.18%
Winter Average		0.52%	1.35%	1.43%	-5.69%	0.58%	-3.02%	0.52%
Spring Average		0.46%	0.92%	1.50%	-1.74%	0.61%	-3.03%	0.53%
Summer Average		0.19%	1.03%	1.18%	-3.55%	0.34%	-2.55%	0.19%
Fall Average		0.26%	1.07%	1.07%	-4.73%	0.32%	-2.54%	0.18%
Annual Average		0.36%	1.09%	1.29%	-3.93%	0.46%	-2.79%	0.36%

Legend
Largest Shift Factor per Methodology
Smallest Shift Factor per Methodology

Table 13 Load Flow Shift Factors Required For Each Methodology (Part "b")

		Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
Loading Condition	Average Loss Factor	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology	Direct Methodology	Direct Methodology	Gradient Methodology	Gradient Methodology
WnPk	4.77%	2.07%	1.43%	-4.79%	-4.57%	-0.01%	0.10%	2.07%	7.87%	-2.84%	-0.70%
WnMd	5.16%	3.75%	2.88%	-5.25%	-4.99%	-0.04%	0.09%	1.73%	7.47%	-3.62%	-1.84%
WnLw	6.42%	4.19%	3.99%	-7.82%	-6.37%	-0.70%	0.02%	0.86%	6.58%	-6.77%	-5.72%
SpPk	5.01%	2.06%	1.48%	-4.93%	-4.84%	0.04%	0.09%	1.91%	7.87%	-3.19%	-1.67%
SpMd	5.05%	3.30%	2.43%	-5.09%	-4.90%	-0.02%	0.07%	1.63%	8.21%	-3.66%	-2.16%
SpLw	6.41%	3.38%	3.37%	-7.66%	-6.47%	-0.62%	-0.03%	0.93%	6.85%	-6.87%	-7.16%
SmPk	4.32%	1.69%	1.20%	-4.80%	-4.15%	-0.24%	0.08%	1.79%	6.67%	-2.95%	-0.43%
SmMd	4.55%	3.44%	2.67%	-5.12%	-4.42%	-0.29%	0.06%	1.34%	6.43%	-3.66%	-1.85%
SmLw	6.03%	3.04%	3.43%	-8.02%	-6.05%	-0.99%	-0.01%	0.57%	5.93%	-7.14%	-6.41%
FlPk	4.22%	1.03%	0.58%	-4.50%	-4.06%	-0.14%	0.08%	0.57%	6.26%	-2.61%	-0.51%
FlMd	4.65%	3.70%	2.93%	-5.36%	-4.53%	-0.35%	0.06%	1.30%	5.64%	-3.81%	-2.09%
FlLw	5.86%	3.24%	3.42%	-7.70%	-5.86%	-0.92%	0.00%	0.74%	5.55%	-6.77%	-5.73%
Winter Average		3.34%	2.77%	-5.95%	-5.31%	-0.25%	0.07%	1.55%	7.31%	-4.41%	-2.75%
Spring Average		2.91%	2.43%	-5.90%	-5.40%	-0.20%	0.04%	1.49%	7.64%	-4.57%	-3.66%
Summer Average		2.72%	2.43%	-5.98%	-4.88%	-0.51%	0.04%	1.23%	6.34%	-4.58%	-2.90%
Fall Average		2.66%	2.31%	-5.85%	-4.82%	-0.47%	0.05%	0.87%	5.82%	-4.40%	-2.78%
Annual Average		2.91%	2.48%	-5.92%	-5.10%	-0.36%	0.05%	1.29%	6.78%	-4.49%	-3.02%

		Uncorrected R-matrix	Corrected R-matrix	Kron Matrix	Kron Matrix	Kron Matrix	Corrected R-matrix	Branch Loss Matrix
Loading Condition	Average Loss Factor	Gradient/2 Methodology	Gradient/2 Methodology	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology	ILF Methodology	Flow Tracking
WnPk	4.77%	0.96%	2.03%	1.19%	-11.95%	0.65%	-2.50%	0.51%
WnMd	5.16%	0.77%	1.66%	1.28%	-7.63%	0.68%	-2.89%	0.50%
WnLw	6.42%	-0.18%	0.35%	1.82%	2.50%	0.40%	-3.68%	0.55%
SpPk	5.01%	0.91%	1.67%	1.26%	-9.02%	0.70%	-2.68%	0.56%
SpMd	5.05%	0.69%	1.45%	1.27%	-5.68%	0.75%	-2.83%	0.50%
SpLw	6.41%	-0.23%	-0.37%	1.98%	9.49%	0.38%	-3.57%	0.54%
SmPk	4.32%	0.68%	1.94%	0.91%	-11.19%	0.49%	-2.13%	0.20%
SmMd	4.55%	0.44%	1.35%	0.90%	-5.28%	0.47%	-2.45%	0.18%
SmLw	6.03%	-0.55%	-0.19%	1.72%	5.81%	0.06%	-3.08%	0.19%
FlPk	4.22%	0.81%	1.86%	0.86%	-12.00%	0.46%	-1.93%	0.20%
FlMd	4.65%	0.42%	1.28%	0.89%	-5.52%	0.39%	-2.51%	0.17%
FlLw	5.86%	-0.45%	0.07%	1.47%	3.33%	0.11%	-3.18%	0.18%
Winter Average		0.52%	1.35%	1.43%	-5.69%	0.58%	-3.02%	0.52%
Spring Average		0.46%	0.92%	1.50%	-1.74%	0.61%	-3.03%	0.53%
Summer Average		0.19%	1.03%	1.18%	-3.55%	0.34%	-2.55%	0.19%
Fall Average		0.26%	1.07%	1.07%	-4.73%	0.32%	-2.54%	0.18%
Annual Average		0.36%	1.09%	1.29%	-3.93%	0.46%	-2.79%	0.36%

Legend
Largest Shift Factor Per Load Flow or Season
Smallest Shift Factor Per Load Flow or Season

Table 14 Range of Loss Factors per Methodology

	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
	Swing Bus Methodology	Swing Bus Methodology	Area Load Methodology	Area Load Methodology	50% Area Load Methodology	50% Area Load Methodology
Maximum Loss Factor	28.72%	18.88%	26.57%	17.82%	15.89%	11.51%
Minimum Loss Factor	-33.14%	-21.29%	-29.76%	-19.21%	-12.28%	-7.00%
Range of Loss Factors	61.86%	40.17%	56.33%	37.03%	28.17%	18.52%
No. Greater Than Maximum Permitted	20	20	20	20	19	3
No. Less Than Minimum Permitted	66	60	63	58	38	9
No of Generators Exceeding Criteria	86	80	83	78	57	12
Seasonal Volatility	11.45%	11.37%	10.22%	10.31%	4.87%	4.92%

	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix	Uncorrected R-matrix	Corrected R-matrix
	Direct Methodology	Direct Methodology	Gradient Methodology	Gradient Methodology	Gradient/2 Methodology	Gradient/2 Methodology
Maximum Loss Factor	16.15%	7.95%	26.91%	18.12%	16.06%	11.66%
Minimum Loss Factor	-18.13%	-24.16%	-30.34%	-19.77%	-12.57%	-7.28%
Range of Loss Factors	34.28%	32.12%	57.25%	37.89%	28.62%	18.95%
No. Greater Than Maximum Permitted	17	0	20	20	20	3
No. Less Than Minimum Permitted	41	19	64	60	40	9
No of Generators Exceeding Criteria	58	19	84	80	60	12
Seasonal Volatility	8.07%	6.78%	10.43%	10.69%	4.98%	5.10%

	Kron Matrix	Kron Matrix	Kron Matrix	Corrected R-matrix	Branch Loss Matrix
	Direct Methodology	Swing Bus Methodology	Gradient/2 Methodology	ILF Methodology	Flow Tracking
Maximum Loss Factor	10.33%	17.29%	11.23%	16.36%	31.93%
Minimum Loss Factor	-5.30%	-18.06%	-6.35%	-20.74%	0.36%
Range of Loss Factors	15.62%	35.35%	17.57%	37.11%	31.57%
No. Greater Than Maximum Permitted	0	20	3	20	4
No. Less Than Minimum Permitted	1	57	2	58	0
No of Generators Exceeding Criteria	1	77	5	78	4
Seasonal Volatility	4.01%	9.02%	4.46%	7.28%	78.73%

Legend
- Largest Magnitude per Methodology
- Smallest Magnitude per Methodology

Table 15 Ranking of Methodologies Based on Magnitude of Shift Factor

Loading Condition	Average Loss Factor	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology
WnPk	4.77%	11	8	15	14	1	2	10	16	13	5
WnMd	5.16%	13	10	15	14	1	2	8	16	12	9
WnLw	6.42%	12	11	17	14	6	1	7	15	16	13
SpPk	5.01%	11	7	15	14	1	2	10	16	13	8
SpMd	5.05%	12	10	15	14	1	2	8	17	13	9
SpLw	6.41%	10	9	16	12	6	1	7	13	14	15
SmPk	4.32%	9	8	15	14	3	1	10	16	13	4
SmMd	4.55%	12	11	15	14	3	1	7	17	13	9
SmLw	6.03%	9	11	17	14	7	1	6	13	16	15
FlPk	4.22%	10	7	15	14	2	1	6	16	13	5
FlMd	4.65%	12	11	15	14	3	1	8	17	13	9
FlLw	5.86%	10	12	17	15	7	1	6	13	16	14
Winter Average		12	10	16	14	2	1	8	17	13	9
Spring Average		11	10	16	15	2	1	7	17	14	13
Summer Average		11	9	16	15	5	1	8	17	14	12
Fall Average		11	9	17	15	5	1	6	16	13	12
Annual Average		11	9	16	15	4	1	7	17	14	12
Weighted Average		11.06	9.36	15.94	14.56	3.64	1.11	7.33	16.39	13.75	11.03
Overall Ranking		12	9	16	15	4	1	7	17	14	11

Loading Condition	Average Loss Factor	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology	Branch Loss Matrix Flow Tracking
WnPk	4.77%	6	9	7	17	4	12	3
WnMd	5.16%	5	7	6	17	4	11	3
WnLw	6.42%	2	3	8	9	4	10	5
SpPk	5.01%	5	9	6	17	4	12	3
SpMd	5.05%	4	7	6	16	5	11	3
SpLw	6.41%	2	3	8	17	4	11	5
SmPk	4.32%	6	11	7	17	5	12	2
SmMd	4.55%	4	8	6	16	5	10	2
SmLw	6.03%	5	4	8	12	2	10	3
FlPk	4.22%	8	11	9	17	4	12	3
FlMd	4.65%	5	7	6	16	4	10	2
FlLw	5.86%	5	2	8	11	3	9	4
Winter Average		3	6	7	15	5	11	4
Spring Average		3	6	8	9	5	12	4
Summer Average		3	6	7	13	4	10	2
Fall Average		3	7	8	14	4	10	2
Annual Average		2	6	8	13	5	10	3
Weighted Average		3.25	6.33	7.53	13.64	4.50	10.53	3.06
Overall Ranking		3	6	8	13	5	10	1

Legend
Largest Ranking Per Load Flow or Season
Smallest Ranking Per Load Flow or Season

Table 16 Overall Ranking Of Methodologies

Criteria	Weighting	Uncorrected R-matrix Swing Bus Methodology	Corrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Corrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Corrected R-matrix 50% Area Load Methodology
Shift Factor	1	12	9	16	15	4	1
Number of Generators That Exceed the Limits	1	17	13	15	11	7	4
Range of Loss Factors	1	17	14	15	11	5	3
Seasonal Volatility	1	16	15	11	12	3	4
Swing Independent	1	15	15	1	1	1	1
Weighted Sum		15.40	13.20	11.60	10.00	4.00	2.60
Final Ranking		17	16	13	11	2	1

Criteria	Weighting	Uncorrected R-matrix Direct Methodology	Corrected R-matrix Direct Methodology	Uncorrected R-matrix Gradient Methodology	Corrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology	Corrected R-matrix Gradient/2 Methodology
Shift Factor	1	7	17	14	11	3	6
Number of Generators That Exceed the Limits	1	8	6	16	13	9	4
Range of Loss Factors	1	9	8	16	13	6	4
Seasonal Volatility	1	9	7	13	14	5	6
Swing Independent	1	1	1	1	1	1	1
Weighted Sum		6.80	7.80	12.00	10.40	4.80	4.20
Final Ranking		8	9	15	12	4	3

Criteria	Weighting	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology	Branch Loss Matrix Flow Tracking
Shift Factor	1	8	13	5	10	1
Number of Generators That Exceed the Limits	1	1	10	3	11	2
Range of Loss Factors	1	1	10	2	12	7
Seasonal Volatility	1	1	10	2	8	17
Swing Independent	1	15	15	15	1	1
Weighted Sum		5.20	11.60	5.40	8.40	5.60
Final Ranking		5	13	6	10	7

Legend

1	Ranking =1
2	Ranking = 2 or 3
15	Ranking >= 4

Table 17 Overall Ranking Of Corrected Matrix Methodologies

Criteria	Weighting	Corrected R-matrix Swing Bus Methodology	Corrected R-matrix Area Load Methodology	Corrected R-matrix 50% Area Load Methodology	Corrected R-matrix Direct Methodology	Corrected R-matrix Gradient Methodology	Corrected R-matrix Gradient/2 Methodology
Shift Factor	1	6	10	1	11	8	4
Number of Generators That Exceed the Limits	1	10	8	4	6	10	4
Range of Loss Factors	1	11	8	3	6	10	4
Seasonal Volatility	1	10	8	3	5	9	4
Swing Independent	1	9	1	1	1	1	1
Weighted Sum		9.20	7.00	2.40	5.80	7.60	3.40
Final Ranking		11	8	1	6	9	2

Criteria	Weighting	Kron Matrix Direct Methodology	Kron Matrix Swing Bus Methodology	Kron Matrix Gradient/2 Methodology	Corrected R-matrix ILF Methodology	Branch Loss Matrix Flow Tracking
Shift Factor	1	5	9	3	7	1
Number of Generators That Exceed the Limits	1	1	7	3	8	2
Range of Loss Factors	1	1	7	2	9	5
Seasonal Volatility	1	1	7	2	6	11
Swing Independent	1	9	9	9	1	1
Weighted Sum		3.40	7.80	3.80	6.20	4.00
Final Ranking		2	10	4	7	5

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 18 Overall Ranking Of Uncorrected Matrix Methodologies

Criteria	Weighting	Uncorrected R-matrix Swing Bus Methodology	Uncorrected R-matrix Area Load Methodology	Uncorrected R-matrix 50% Area Load Methodology	Uncorrected R-matrix Direct Methodology	Uncorrected R-matrix Gradient Methodology	Uncorrected R-matrix Gradient/2 Methodology
Shift Factor	1	4	6	2	3	5	1
Number of Generators That Exceed the Limits	1	6	4	1	2	5	3
Range of Loss Factors	1	6	4	1	3	5	2
Seasonal Volatility	1	6	4	1	3	5	2
Swing Independent	1	6	1	1	1	1	1
Weighted Sum		5.60	3.80	1.20	2.40	4.20	1.80
Final Ranking		6	4	1	3	5	2

Legend		
	1	Ranking =1
	2	Ranking = 2 or 3
	15	Ranking >= 4

Table 19 Loss Factors by Load Flow Area, 50% Area Load Corrected Matrix Methodology

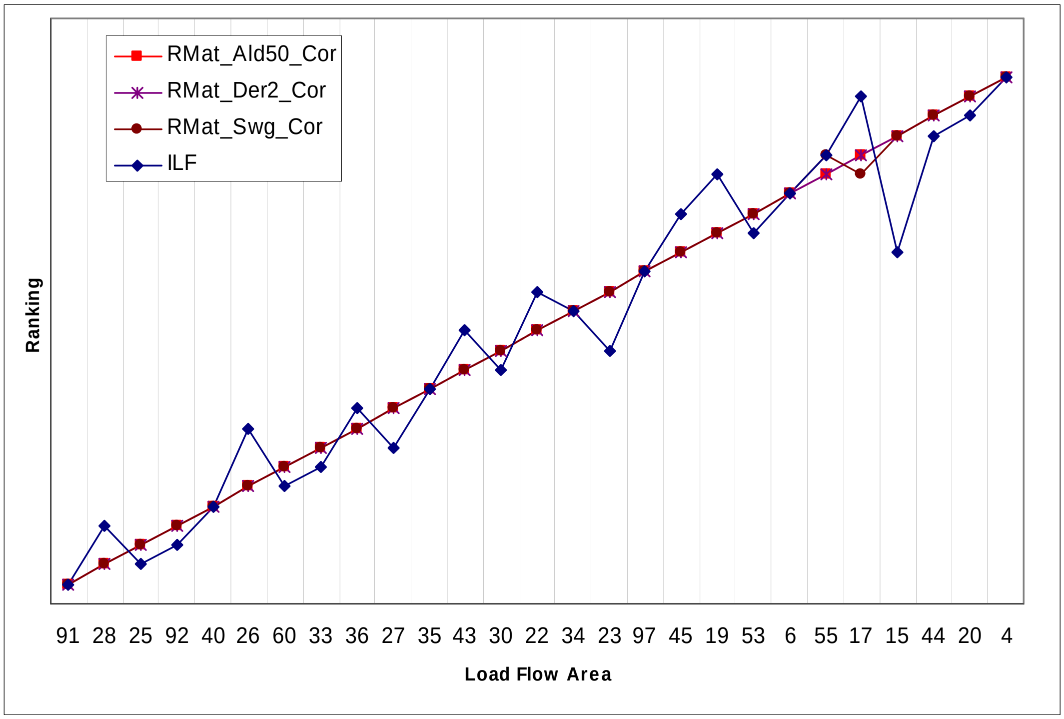
Area	Average	Maximum	Minimum	Range
4	-5.81%	-5.66%	-5.93%	0.27%
6	-3.09%	-2.73%	-3.46%	0.74%
15	-4.16%	-4.16%	-4.16%	0.00%
17	-3.90%	-3.35%	-4.05%	0.70%
19	-2.67%	-2.67%	-2.67%	0.00%
20	-4.60%	-2.57%	-7.00%	4.44%
22	0.68%	0.68%	0.68%	0.00%
23	-0.33%	0.09%	-0.54%	0.63%
25	8.92%	9.24%	8.63%	0.62%
26	4.01%	4.01%	4.01%	0.00%
27	3.26%	3.26%	3.26%	0.00%
28	9.40%	11.10%	8.26%	2.84%
30	0.88%	1.12%	0.50%	0.62%
33	3.78%	4.23%	3.04%	1.19%
34	-0.10%	0.02%	-0.22%	0.24%
35	1.59%	1.85%	1.41%	0.43%
36	3.74%	4.18%	2.92%	1.26%
40	6.11%	6.42%	5.67%	0.76%
43	1.04%	1.07%	1.02%	0.05%
44	-4.33%	-3.89%	-4.86%	0.98%
45	-2.55%	-1.81%	-3.31%	1.50%
53	-2.80%	-1.58%	-3.77%	2.19%
55	-3.89%	-3.01%	-4.77%	1.77%
60	3.94%	3.97%	3.84%	0.13%
91	10.24%	11.51%	9.98%	1.53%
92	8.88%	8.97%	8.82%	0.14%
97	-2.17%	2.33%	-4.69%	7.03%

Legend	
	Maximum
	Minimum
	Range > 2% < max

Table 20 Loss Factors by Load Flow Area, 50% Area Load Uncorrected Matrix Methodology

Area	Average	Maximum	Minimum	Range
4	-7.51%	-7.31%	-7.66%	0.35%
6	-4.34%	-3.99%	-4.70%	0.70%
15	-6.41%	-6.41%	-6.41%	0.00%
17	-12.04%	-11.28%	-12.28%	1.00%
19	-5.12%	-5.12%	-5.12%	0.00%
20	-6.15%	-3.74%	-9.00%	5.26%
22	-0.10%	-0.10%	-0.10%	0.00%
23	-1.05%	-0.54%	-1.31%	0.78%
25	12.30%	12.66%	11.95%	0.70%
26	3.99%	3.99%	3.99%	0.00%
27	3.98%	3.98%	3.98%	0.00%
28	11.82%	13.84%	10.39%	3.45%
30	0.35%	0.54%	0.01%	0.53%
33	4.20%	4.53%	3.64%	0.89%
34	-0.69%	-0.57%	-0.82%	0.25%
35	0.90%	1.13%	0.75%	0.39%
36	2.77%	3.28%	1.82%	1.46%
40	5.98%	6.46%	5.15%	1.31%
43	-0.72%	-0.70%	-0.74%	0.04%
44	-5.88%	-5.12%	-6.84%	1.72%
45	-3.97%	-3.15%	-4.80%	1.65%
53	-5.00%	-3.83%	-6.06%	2.23%
55	-6.01%	-5.00%	-7.03%	2.04%
60	4.14%	4.16%	4.10%	0.06%
91	13.83%	15.89%	13.43%	2.46%
92	12.23%	12.33%	12.17%	0.16%
97	-3.83%	1.95%	-6.92%	8.88%

Legend	
	Maximum
	Minimum
	Range > 2% < max



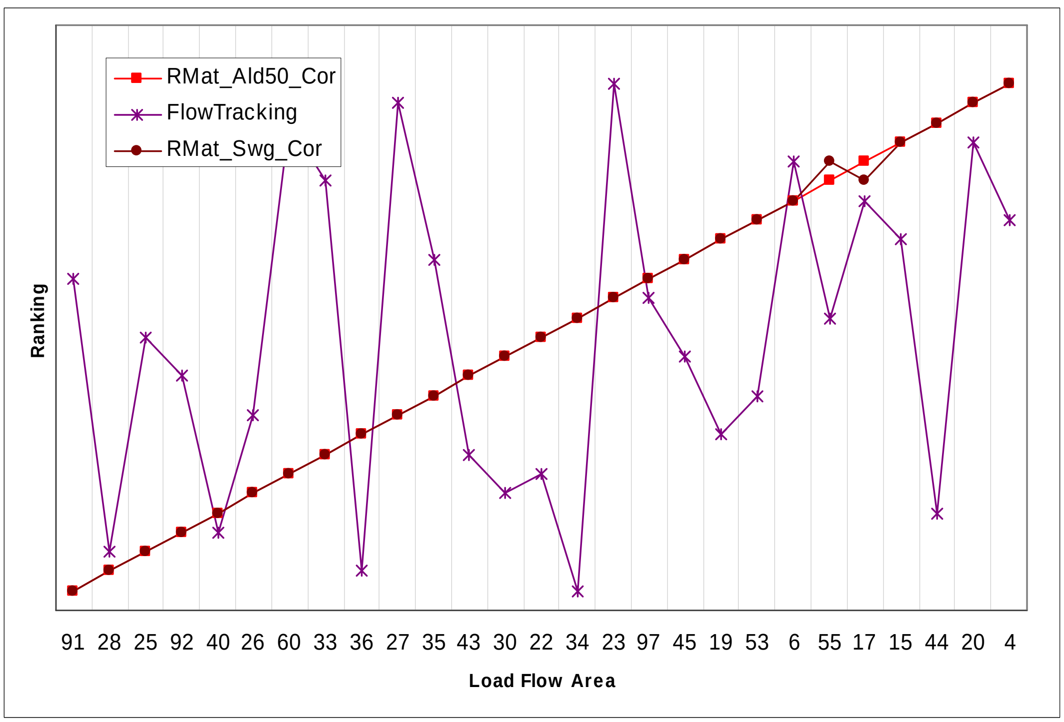


Figure 11 Ranking of Loss Factors by Load Flow Area

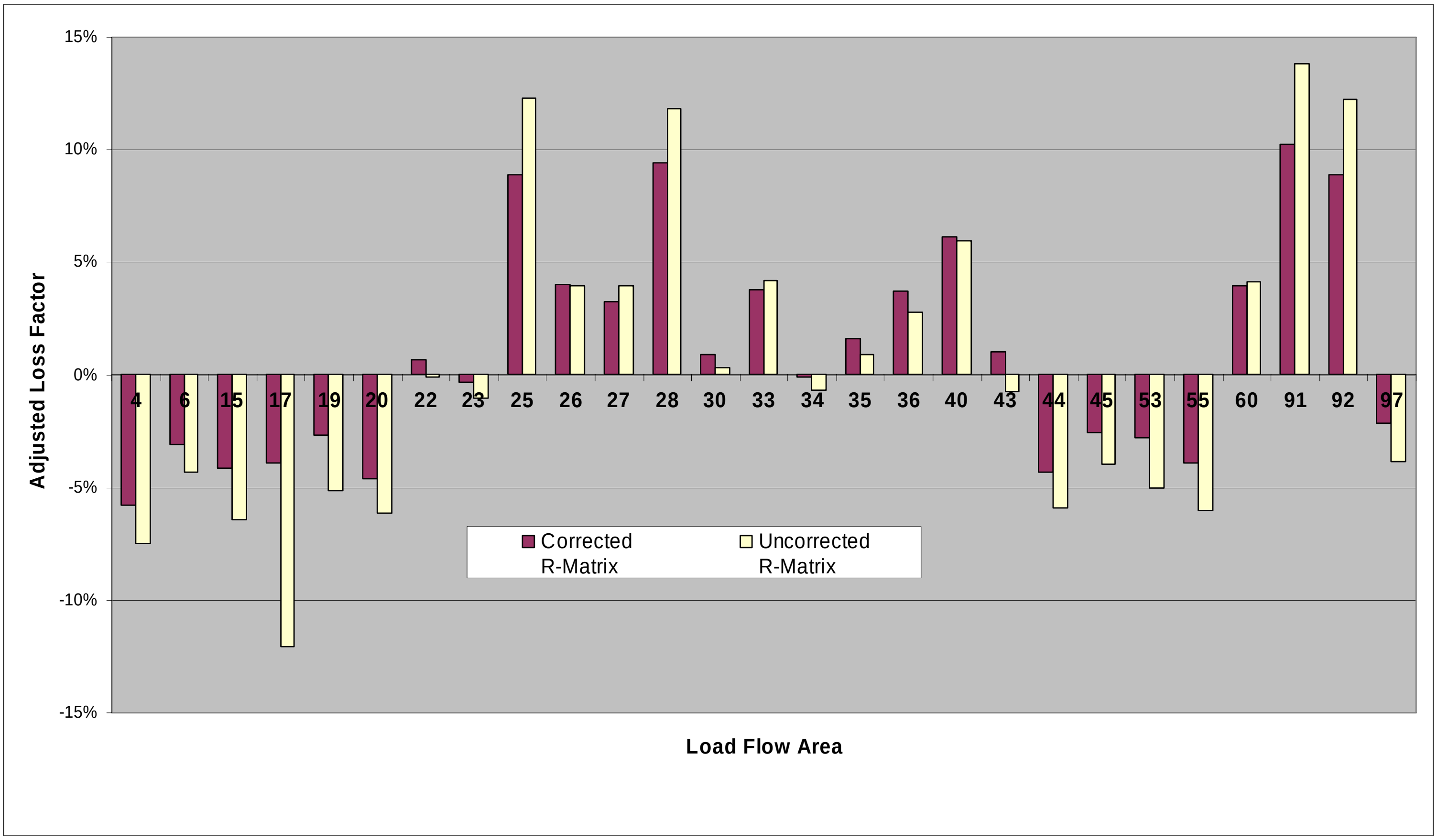


Figure 12 Comparison of Adjusted Average Loss Factors Using Corrected and Uncorrected R-Matrices

Appendix A

Derivation of 50% Area Load Adjustment Loss Factors

Losses ‘ L ’ can be calculated from two simultaneous equations.

$$\mathrm{L} = (\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot (\mathbf{Pg} + \mathbf{Pl}) \quad \text{Equation 1}$$

$$\mathrm{L} = \sum_{i} (\mathbf{Pg}_i + \mathbf{Pl}_i) \quad \text{Equation 2}$$

R is the real component of the inverse of the corrected symmetrical open circuit admittance matrix.
Pg is a vector of all the generator power injections at each of the nodes defined by the **R** matrix (normally positive)
Pl is a vector of power injections due to loads at each of the nodes (normally negative)

From Equation 1, the change in losses due to a change in generator output $\Delta \mathrm{Pg}_j$ at node ‘j’ is:

$$\Delta \underset{j}{\mathrm{L}} = 2 \cdot (\mathbf{Pg} + \mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot (\mathbf{\Delta} \underset{j}{\mathbf{Pg}} + \mathbf{\Delta} \underset{j}{\mathbf{Pl}}) \quad \text{Equation 3}$$

where:

$$\mathbf{\Delta} \underset{j}{\mathbf{Pg}} = \begin{bmatrix} 0 & \cdots & 0 & 1 & 0 & \cdots & 0 \end{bmatrix}^{\mathrm{T}} \Delta \mathrm{Pg}_j \quad \text{Equation 4}$$

and the change in distributed load to accommodate the change in generation is:

$$\mathbf{\Delta} \underset{j}{\mathbf{Pl}} = \underset{j}{\delta} \cdot \mathbf{Pl} \quad \text{Equation 5}$$

where: $\underset{j}{\delta} \cdot$ is an adjustment factor applied to all loads due to the change in generation at node ‘j’.

From equation 2, then the change in losses is also equal to:

$$\Delta \underset{j}{\mathrm{L}} = \Delta \mathrm{Pg}_j + \underset{j}{\delta} \cdot \sum_i \mathbf{Pl}_i \quad \text{Equation 6}$$

The required load adjustment factor is therefore:

$$\underset{j}{\delta} = \frac{\Delta \underset{j}{\mathrm{L}} - \Delta \mathrm{Pg}_j}{\sum_i \mathbf{Pl}_i} \quad \text{Equation 7}$$

Substituting into equation 3 for $\mathbf{\Delta} \underset{j}{\mathbf{Pg}}$, $\mathbf{\Delta} \underset{j}{\mathbf{Pl}}$, and $\underset{j}{\delta}$ yields:

$$\Delta L_j = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\left(\begin{bmatrix}0 & \cdots & 0 & 1 & 0 & \cdots & 0\end{bmatrix}^{\mathrm{T}}\Delta Pg_j + \left(\frac{\Delta L_j - \Delta Pg_j}{\sum_i \mathbf{Pl}_i}\right)\cdot\mathbf{Pl}\right) \qquad \text{Equation 8}$$

Dividing by ΔPg_j

$$\frac{\Delta L_j}{\Delta Pg_j} = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\left(\begin{bmatrix}0 & \cdots & 0 & 1 & 0 & \cdots & 0\end{bmatrix}^{\mathrm{T}} + \left(\frac{\Delta L_j}{\Delta Pg_j} - 1\right)\cdot\frac{\mathbf{Pl}}{\sum_i \mathbf{Pl}_i}\right) \qquad \text{Equation 9}$$

Collecting terms:

$$\frac{\Delta L_j}{\Delta Pg_j}\left(1 - 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\frac{\mathbf{Pl}}{\sum_i \mathbf{Pl}_i}\right) = -2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\frac{\mathbf{Pl}}{\sum_i \mathbf{Pl}_i}$$
$$+2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\begin{bmatrix}0 & \cdots & 0 & 1 & 0 & \cdots & 0\end{bmatrix}^{\mathrm{T}} \qquad \text{Equation 10}$$

Defining:

$$\alpha = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\frac{\mathbf{Pl}}{\sum_i \mathbf{Pl}_i} \qquad \text{Equation 11}$$

Equation 10 can be re-written:

$$\frac{\Delta L_j}{\Delta Pg_j}(1-\alpha)+\alpha = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\begin{bmatrix}0 & \cdots & 0 & 1 & 0 & \cdots & 0\end{bmatrix}^{\mathrm{T}} \qquad \text{Equation 12}$$

Considering the generation at node 1:

$$\frac{\Delta L_1}{\Delta Pg_1}(1-\alpha)+\alpha = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\begin{bmatrix}1 & 0 & \cdots & 0\end{bmatrix}^{\mathrm{T}} \qquad \text{Equation 13}$$

Multiplying by the generation at node 1, Pg_1 gives:

$$\frac{\Delta L_1}{\Delta Pg_1}(1-\alpha)\cdot Pg_1 + \alpha\cdot Pg_1 = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\begin{bmatrix}Pg_1 & 0 & \cdots & 0\end{bmatrix}^{\mathrm{T}} \qquad \text{Equation 14}$$

Similarly for generation at node 2:

$$\frac{\Delta L_2}{\Delta Pg_2}(1-\alpha)\cdot Pg_2 + \alpha\cdot Pg_2 = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\begin{bmatrix}0 & Pg_2 & 0 & \cdots & 0\end{bmatrix}^{T} \qquad \text{Equation 15}$$

Summing equations similar to 14 and 15 for all nodes:

$$(1-\alpha)\cdot\begin{bmatrix}\dfrac{\Delta L_1}{\Delta Pg_1} & \cdots & \dfrac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}\cdot\mathbf{Pg} + \alpha\cdot\sum_{i}\mathbf{Pg_i} = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pg} \qquad \text{Equation 16}$$

Expanding the second term by substituting for α:

$$\alpha\cdot\sum_{\mathbf{i}}\mathbf{Pg_i} = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\frac{\mathbf{Pl}}{\sum_{i}\mathbf{Pl}_i}\sum_{i}\mathbf{Pg_i} \qquad \text{Equation 17}$$

Rearranging the terms:

$$\alpha\cdot\sum_{\mathbf{i}}\mathbf{Pg_i} = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pl}\cdot\frac{\sum_{i}\mathbf{Pg_i}}{\sum_{i}\mathbf{Pl}_i} \qquad \text{Equation 18}$$

From equation 2:

$$\sum_{i}\mathbf{Pg}_i = L - \sum_{i}\mathbf{Pl}_i \qquad \text{Equation 19}$$

Substituting into equation 18 for $\sum_{i}\mathbf{Pg}_i$ gives:

$$\alpha\cdot\sum_{i}\mathbf{Pg_i} = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pl}\cdot\left(\frac{L}{\sum_{i}\mathbf{Pl}_i}-1\right) \qquad \text{Equation 20}$$

and substituting for $\alpha\cdot\sum_{\mathbf{i}}\mathbf{Pg_i}$ gives:

$$(1-\alpha)\cdot\begin{bmatrix}\dfrac{\Delta L_1}{\Delta Pg_1} & \cdots & \dfrac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}\cdot\mathbf{Pg} + 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pl}\cdot\left(\frac{L}{\sum_{i}\mathbf{Pl}_i}-1\right) =$$
$$2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pg} \qquad \text{Equation 21}$$

which is equal to:

$$(1-\alpha)\cdot\begin{bmatrix}\dfrac{\Delta L_1}{\Delta Pg_1} & \cdots & \dfrac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}\cdot\mathbf{Pg} + \alpha\cdot L = 2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pg}$$
$$+2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot\mathbf{Pl} \qquad \text{Equation 22}$$

or:

$$(1-\alpha)\cdot\begin{bmatrix}\frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}\cdot\mathbf{Pg}+\alpha\cdot L=2\cdot(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}}\cdot\mathbf{R}\cdot(\mathbf{Pg}+\mathbf{Pl})\qquad\text{Equation 23}$$

$$(1-\alpha)\cdot\begin{bmatrix}\frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}\cdot\mathbf{Pg}+\alpha\cdot L=2L\ \text{Equation 24}$$

Or, collecting terms:

$$(1-\alpha)\cdot\frac{\begin{bmatrix}\frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}}{2}\cdot\mathbf{Pg}=L\cdot\left(1-\frac{\alpha}{2}\right)\qquad\text{Equation 25}$$

Rearranging equation 25:

$$L=\frac{(1-\alpha)}{\left(1-\frac{\alpha}{2}\right)}\cdot\frac{\begin{bmatrix}\frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}}{2}\cdot\mathbf{Pg}\qquad\text{Equation 26}$$

If ‘ α ’ is small

$$L\approx\left(1-\frac{\alpha}{2}\right)\cdot\frac{\begin{bmatrix}\frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}}{2}\cdot\mathbf{Pg}\qquad\text{Equation 27}$$

If the generation vector is divided into two components representing those that pay for losses ‘ $\mathbf{Pg_{ass}}$ ’ and those than do not ‘ $\mathbf{Pg_{unass}}$ ’, i.e.:

$$\mathbf{Pg}=\mathbf{Pg_{ass}}+\mathbf{Pg_{unass}}\qquad\text{Equation 28}$$

then, equation 27 can be re-written:

$$L\approx\left(1-\frac{\alpha}{2}\right)\cdot\frac{\begin{bmatrix}\frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n}\end{bmatrix}}{2}\cdot\left(\mathbf{Pg_{ass}}+\mathbf{Pg_{unass}}\right)\ \text{Equation 29}$$

or:

$$L\approx\mathbf{Lf_{raw}}^{\mathbf{T}}\cdot\mathbf{Pg_{ass}}+L_{shift}\qquad\text{Equation 30}$$

In equation 29, the raw loss factor '$\mathbf{Lf_{raw}}^{\mathbf{T}}$' is defined to be:

$$\mathbf{Lf_{raw}} = \frac{\begin{bmatrix} \frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n} \end{bmatrix}^{\mathbf{T}}}{2} \qquad \text{Equation 31}$$

and 'L_{shift}' represents the losses that are unassigned based on raw loss factors. I.e.:

$$L_{shift} = \left(1 - \frac{\alpha}{2}\right) \frac{\begin{bmatrix} \frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n} \end{bmatrix}}{2} \cdot \mathbf{Pg_{unass}} - \frac{\alpha}{2} \cdot \frac{\begin{bmatrix} \frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n} \end{bmatrix}}{2} \cdot (\mathbf{Pg_{ass}}) \qquad \text{Equation 32}$$

Applying a shift factor to all raw loss factors to recover the unassigned losses, equation 30 can be re-written:

$$L \approx \mathbf{Lf_{raw}}^{\mathbf{T}} \cdot \mathbf{Pg_{ass}} + L_{shift} \cdot [1 \quad \cdots \quad 1]^{\mathbf{T}} \cdot \frac{\mathbf{Pg_{ass}}}{\sum_i \mathbf{Pg_{ass}}_i} \qquad \text{Equation 33}$$

from which:

$$L \approx \mathbf{Lf_{adj}}^{\mathbf{T}} \cdot \mathbf{Pg_{ass}} \qquad \text{Equation 34}$$

where:

$$\mathbf{Lf_{adj}} = \left[\left(\tfrac{1}{2} \frac{\Delta L_1}{\Delta Pg_1} + Sf \right) \quad \cdots \quad \left(\tfrac{1}{2} \frac{\Delta L_n}{\Delta Pg_n} + Sf \right) \right]^{\mathbf{T}} \qquad \text{Equation 35}$$

and from equations 32 and 33:

$$Sf = \frac{\left(1 - \frac{\alpha}{2}\right) \frac{\begin{bmatrix} \frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n} \end{bmatrix}}{2} \cdot \mathbf{Pg_{unass}} - \frac{\alpha}{2} \cdot \frac{\begin{bmatrix} \frac{\Delta L_1}{\Delta Pg_1} & \cdots & \frac{\Delta L_n}{\Delta Pg_n} \end{bmatrix}}{2} \cdot (\mathbf{Pg_{ass}})}{\sum_i \mathbf{Pg_{ass}}_i} \cdot \qquad \text{Equation 36}$$

If from equation 1, if it is assumed that the load and generation will contribute roughly the same order of magnitude to losses, then it can be deduced that the factor 'α' will have an order of magnitude in the range of the average loss factor for the system. With typical loss factors in the range of 5% for the system, the approximation introduced in equation 27 above is valid.
Since the total unassigned generation is less than 1% of the total generation in the system, the component of the shift factor due to unassigned generation in equation 36 will be less than 1% of

typically 5% or less than 0.0005 (0.05%). The component of the loss factor due to approximations in the contribution of the assigned generators will be in the order of 2½ % of 5% or about 0.00125 (0.125%).

Alberta Electric System Operator

Loss Factor Methodologies Evaluation Part 2
Conversion of Power to Energy Loss Factors

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada R3T 0P4

December 20, 2004
Revised December 22, 2004
Revised January 24, 2005

File No: 558-10000

DISCLAIMER

ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION PART 2 CONVERSION OF POWER TO ENERGY LOSS FACTORS

TABLE OF CONTENTS

Page

ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION PART 2 CONVERSION OF POWER TO ENERGY LOSS FACTORS

1. Introduction

This report discusses the results of full system testing of methodologies to convert load flow based loss factors to energy-based values, based on the 50% corrected 'R-Matrix' area load adjustment loss factor calculation methodology. This methodology was selected based on a comparison of a number of methodologies for calculating loss factors [1].

2. Evaluation Methodology

The full Alberta Integrated Electric System (AIES) was used as the basis for all calculations. A full set of twelve 2003 load flow conditions was used as input to the calculations. Each load flow model consists of about 1700 busses, with about 190 generators and about 700 loads connected. Bus number 1520 (the 500 kV equivalent of the BC Hydro and WECC system) was designated as the swing bus for the system.

Loss factors were calculated for each generator in the load flow for each of the 12 load flow conditions using the 50% corrected R-Matrix area load adjustment methodology. The load flows represent peak, medium and light load conditions for each of the winter, spring, summer and fall seasons. The 12 sets of loss factors were combined to give a single loss factor for each generator using two approaches:

1. Un-weighted approach in which the loss factor assigned to each generator is the average of the loss factors determined for each of the load flow conditions.

2. Weighted approach in which the loss factor assigned to each generator is a weighted average of the 12 load flow loss factors. The weighting assigned to each loss factor is discussed in Section 0.

The two sets of loss factors were used to compute the shift factor that would be required to recover all of the energy losses based on the 2004 forecast of generator volumes and total system energy losses. These shift factors were compared to the factors calculated using the existing 'swing' bus methodology and which form the basis of the posted 'normalized' loss factors. The comparison is discussed in Section 0.

Calculated loss factors were not available for 14 of the generators contributing in the range of 5.18% to 5.86% of the total forecast energy volumes. To include the effects of these units in the evaluation of approaches, the units were assigned a loss factor equal to the average loss factor of the system based on load flow results or 5.21%.

3 Determination of Loss Factor Weightings

In the present AESO swing bus based loss factor methodology, loss factors are determined for each generator for each of three loading conditions in each of the four seasons. Separate loss factors are assigned to each generator for each season, equal to the average of the three loss factors calculated for each season.

The Alberta Department of Energy has indicated that for the new methodology, each generator will be assigned a single loss factor based on forecast annual impact on losses. Extending the present philosophy to the new methodology, one method of converting load flow loss factors to energy loss factors is to determine the annual loss factor based on the average of all 12 individual loss factors. This is referenced herein as “equal weighting” since the loss factor from each load flow is assigned the same weighting.

An alternative approach considered was to assign a weighting to each loss factor based on the load duration curve for each season. The projected load duration curves for each of the four seasons for 2005 are shown in Figure 13 through Figure 16. If it is assumed that the shape of the load duration curve for 2003 is not significantly different from the shape for 2005, then the load levels represented by each of the load flows studied can be superimposed on the individual load duration curves. Each of the figures also indicates the average load level for each one-third of the load duration curve (superimposed boxes).

Figure 13 shows that the load flow levels represented by the winter peak and winter medium load flows are less than the respective averages with the winter low load level, greater than its respective average. Similar trends are shown in Figure 14 and Figure 15 for spring and summer conditions. In the fall load flow series, the peak load is greater than the average but the medium and low load conditions exhibit similar trends in all four seasons.

Based on the figures it was concluded that the load flows were not very representative of the average energy from the load duration curve, particularly if equal weighting is assigned to each load flow.

Weightings were determined for each load flow that would minimize the total difference between the load energy represented by each load flow and the load duration curve. These weightings are given in Table 21 and shown graphically in Figure 17 through Figure 20. The differences between the actual energy for each season and the energy calculated using the load flow load levels and the weighting factors given in Table 21 are negligible. The differences are shown in Table 22 and are almost five orders of magnitude less that the total energy.

4 Comparison of Results and Conclusions

A summary of AESO’s calculation of shift factors for the year 2004 based on the 2003 load flows and the current AESO loss factor methodology is given in Table 23. The shift factors vary from –3.89% for the fall conditions to –4.53% for the spring loading conditions. The shift factors are subtracted from the generator individual raw loss factor to determine the normalized loss factors for each generator. As all four shift factors are negative, the normalized loss factor for all of the generators is increased.

The shift factors for 2004 have been re-calculated using the 'raw' loss factors determined with the 50% area load adjustment methodology. The same individual estimated generator volumes and total estimated system losses were used. Only the 'raw' loss factors for each generator were changed. The 'raw' loss factor for each generator was set equal to the direct average of the twelve loss factors determined from each base case load flow.

Raw loss factors were not generated for 14 of the generators. To include their effects, each of these units was assigned a 'raw' loss factor equal to the average annual load flow loss factor of 5.21%. As the total generation associated with these units is about 5% of the total, the net effect of this approximation is to reduce the magnitude of the required shift factor by about ¼%. After including the small adjustment, the shift factors required for the new methodology would be reduced considerably to approximately –1% as shown in Table 24.

The same procedure was repeated, using loss factors for each generator that are weighted using the weighting assigned to each load flow from Table 21. Table 25 shows that although there is practically no improvement in the shift factors for each season. The improvement is not considered sufficient to warrant the extra refinement (and its risk of introducing other inaccuracies).

Even though there is a significant improvement in shift factors over the existing methodology when loss factors calculated using the 50% area load adjustment methodology are used, the shift factor (at about –1%) is still considered large. As the 'raw' loss factors account for 100% of the individual load flow losses, the difference can be directly attributed to differences between load levels and individual generation modeled in each of the load flows and the generator forecasts and total energy loss forecasts used in the calculation of seasonal shift factors.

The roots of the differences could be the subject of further investigations into improving the correlation between load flow losses and energy loss forecasts, as well as the correlation between individual load flow generation and forecast generator volumes

5 References

[1] Report "Alberta Electric System Operator, Loss Factor Methodologies Evaluation, Part 1 - Determination of 'Raw' Loss Factors", prepared by Teshmont Consultants LP, January 24,2005.

Table 21 Load Flow Weighting Factors to Minimize Energy Error

	Winter	Spring	Summer	Fall
Peak	0.51	0.54	0.32	0.24
Medium	0.32	0.14	0.28	0.49
Low	0.17	0.32	0.4	0.27

Table 22 Energy Mismatch Between Load Flows With Weighting Factors and Load Duration Curves

	Winter	Spring	Summer	Fall
Actual Energy (GWh)	17,800	16,800	16,800	17,200
Mismatch (GWh)	-0.13	0.12	-.09	-.01

Table 23 Summary of AESO Shift Factors Based on Current Swing Bus Methodology, Equal Weighting

Season	Winter	Spring	Summer	Fall
Total forecast generator volumes (MWhr)	15,104,377	14,077,162	14,516,509	14,595,855
Total forecast losses (MWhr)	768,108	723,355	700,193	681,626
Total non-normalized energy losses	119,662	130,427	43,739	113,926
Unassigned energy losses	648,447	592,929	656,455	567,699
Required Shift Factor	-4.29%	-4.21%	-4.52%	-3.89%
Note Shift factor is subtracted from individual generator raw loss factors to obtain normalised loss factors				

Table 24 Shift Factors Based on 50% Area Load Adjustment Methodology Calculated with Equal Weighting

Season	Winter	Spring	Summer	Fall
Total forecast generator volumes (MWhr)	15,104,377	14,077,162	14,516,509	14,595,855
Total forecast losses (MWhr)	768,108	723,355	700,193	681,626
Non-normalized energy losses based on available raw loss factors	575,648	517,801	510,353	537,749
Estimate of other contributions	40,710	39,665	42,408	44,546
Total non-normalized energy losses	641,506	565,092	556,671	607,466
Unassigned Energy Losses	126,603	158,263	143,523	74,159
Required Shift Factor	-0.84%	-1.12%	-0.99%	-0.51%
Note Shift factor is subtracted from individual generator raw loss factors to obtain normalized loss factors				

Table 25 Shift Factors Based on 50% Area Load Adjustment Methodology Calculated with Optimized Weighting

Season	Winter	Spring	Summer	Fall
Total forecast generator volumes (MWhr)	15,104,377	14,077,162	14,516,509	14,595,855
Total forecast losses (MWhr)	768,108	723,355	700,193	681,626
Non-normalized energy losses based on available raw loss factors	576,964	519,636	512,419	538,743
Estimate of other contributions	40,710	39,665	42,408	44,546
Total non-normalized energy losses	641,770	566,498	558,172	607,297
Unassigned Energy Losses	126,338	156,857	142,021	74,329
Required Shift Factor	-0.84%	-1.11%	-0.98%	-0.51%
Note Shift factor is subtracted from individual generator raw loss factors to obtain normalised loss factors				

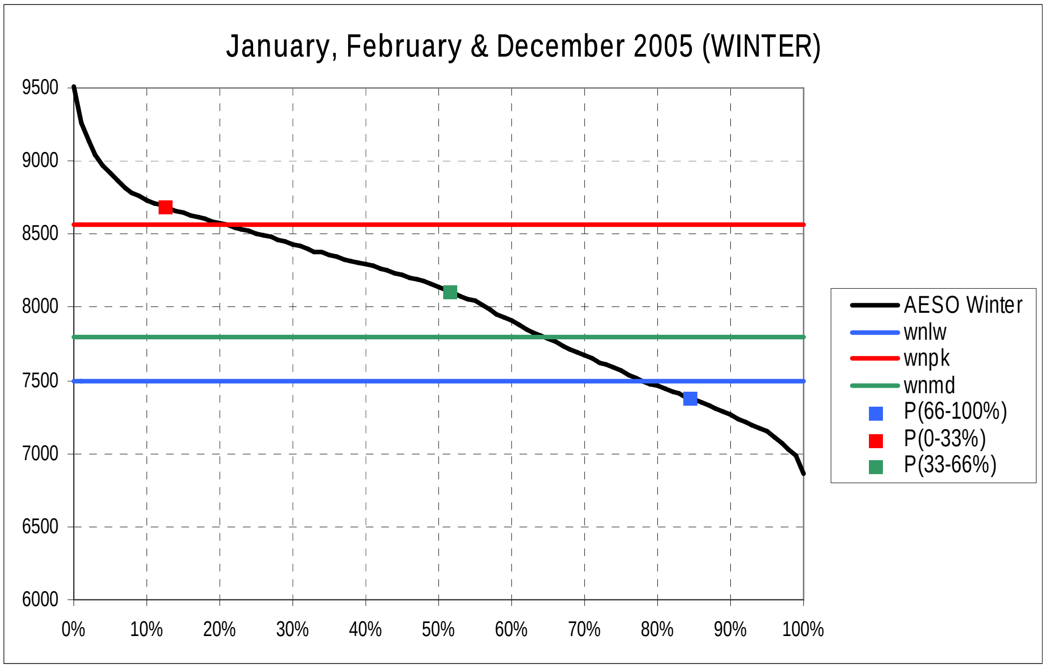


Figure 13 **Comparison of 2003 Winter Load Flow Levels with 2005 Load Duration Curve**

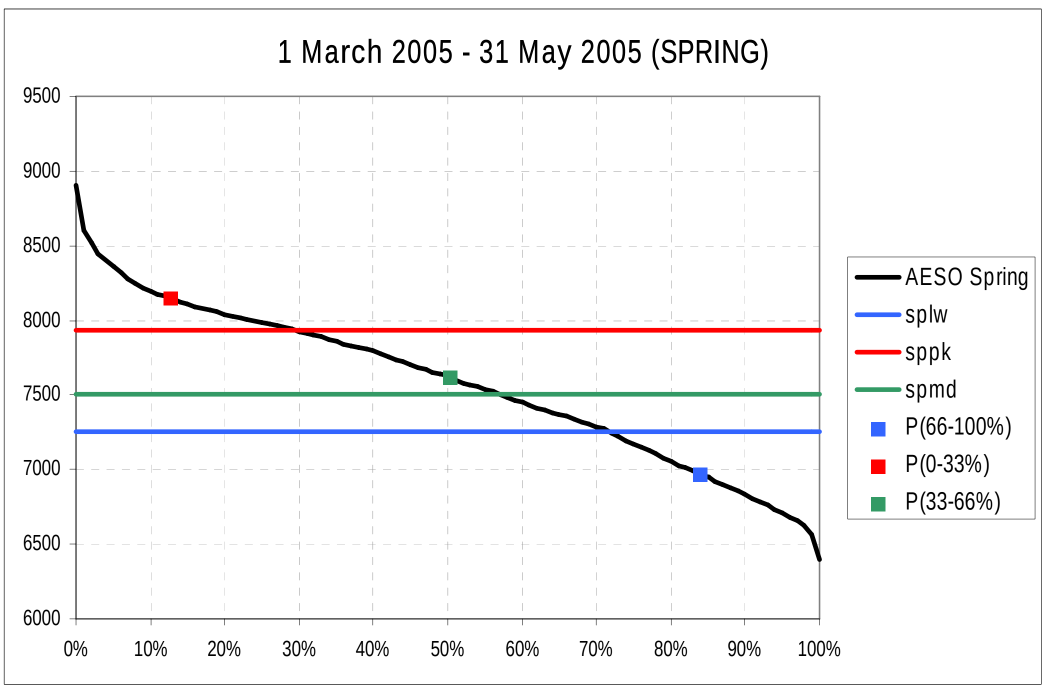


Figure 14 **Comparison of 2003 Spring Load Flow Levels with 2005 Load Duration Curve**

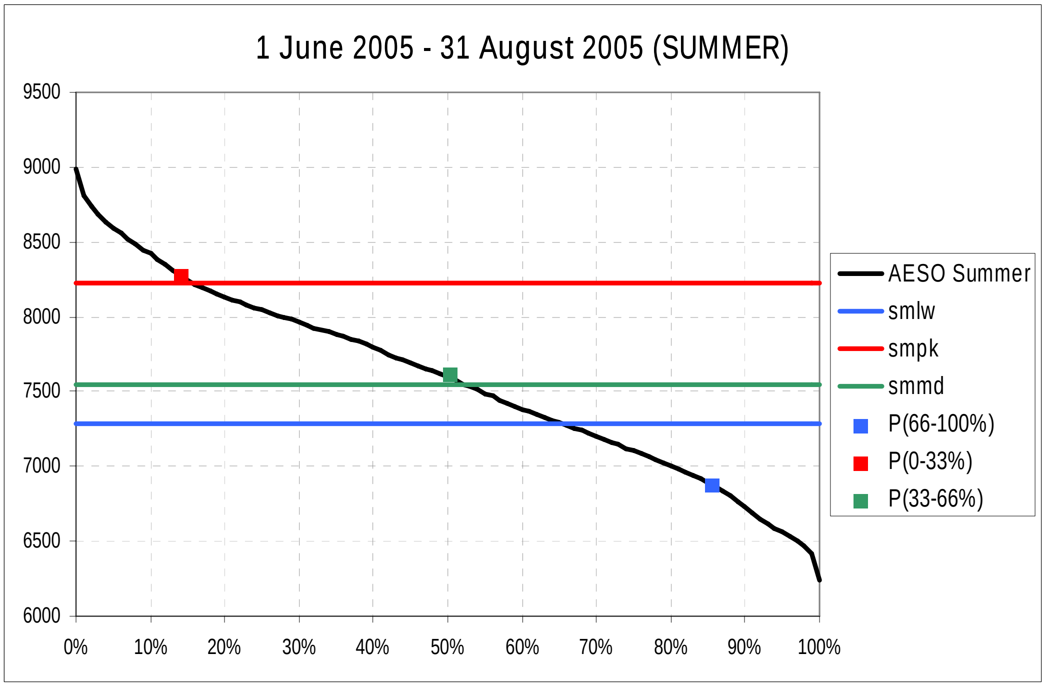


Figure 15 **Comparison of 2003 Summer Load Flow Levels with 2005 Load Duration Curve**

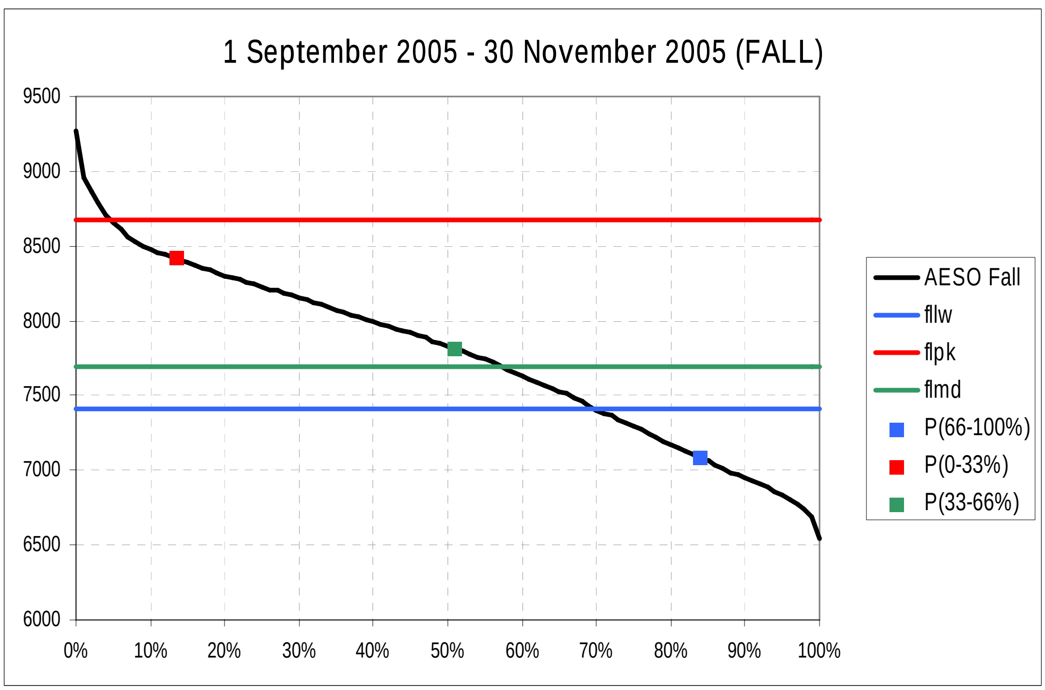


Figure 16 **Comparison of 2003 Fall Load Flow Levels with 2005 Load Duration Curve**

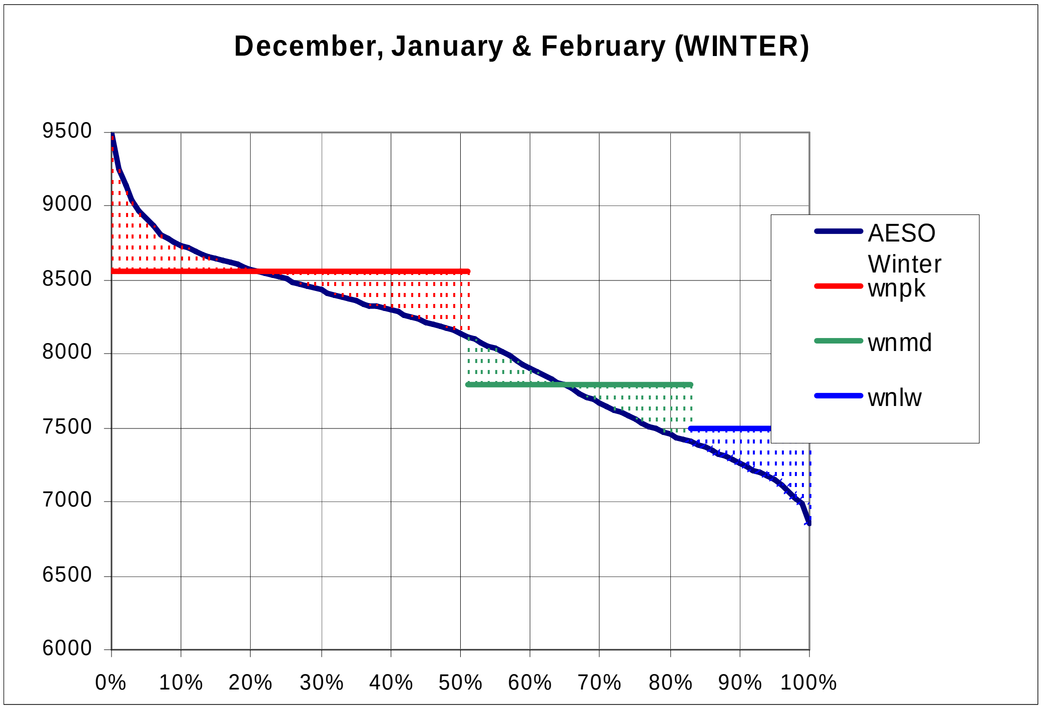


Figure 17 Weightings Based on Winter Load Flow Levels

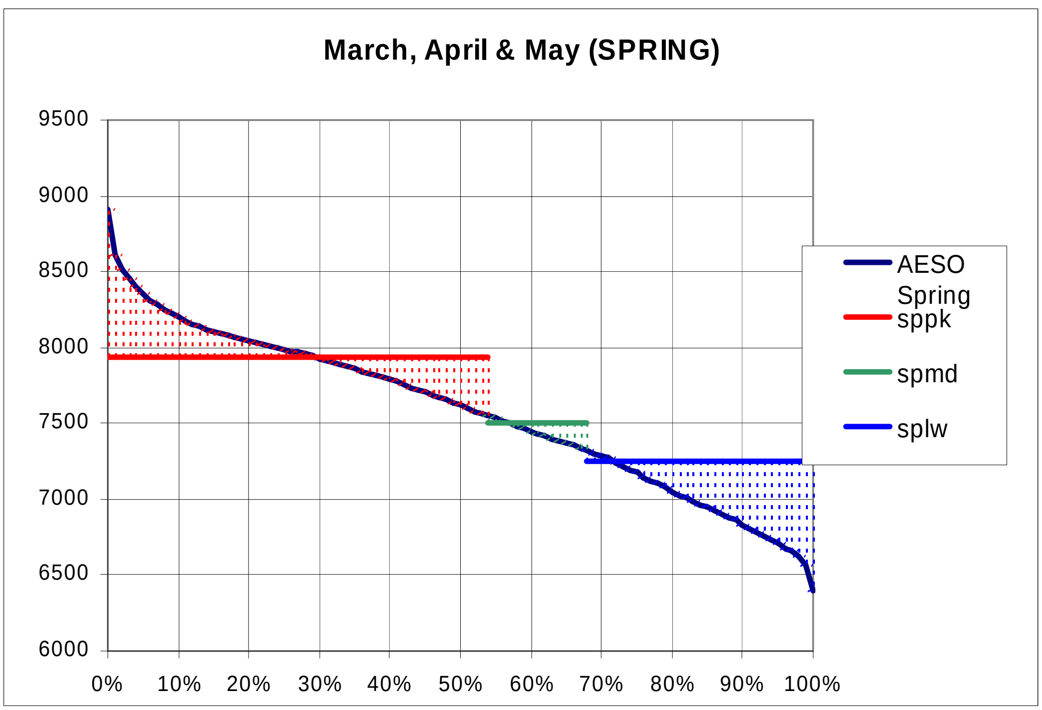


Figure 18 Weightings Based on Spring Load Flow Levels

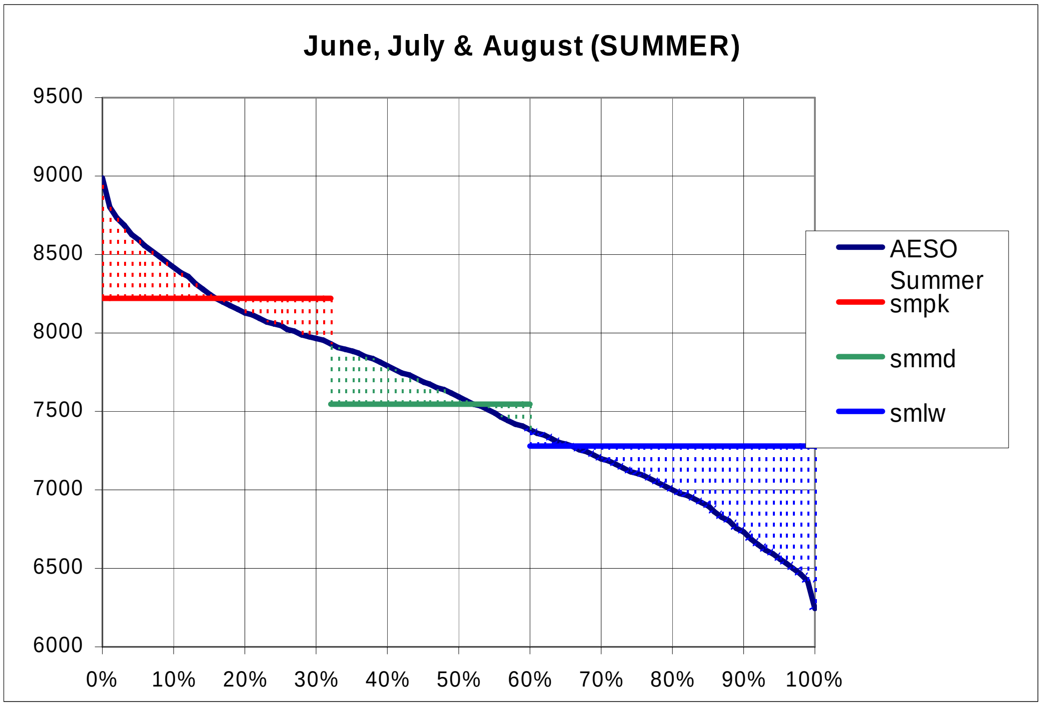


Figure 19 **Weightings Based on Summer Load Flow Levels**

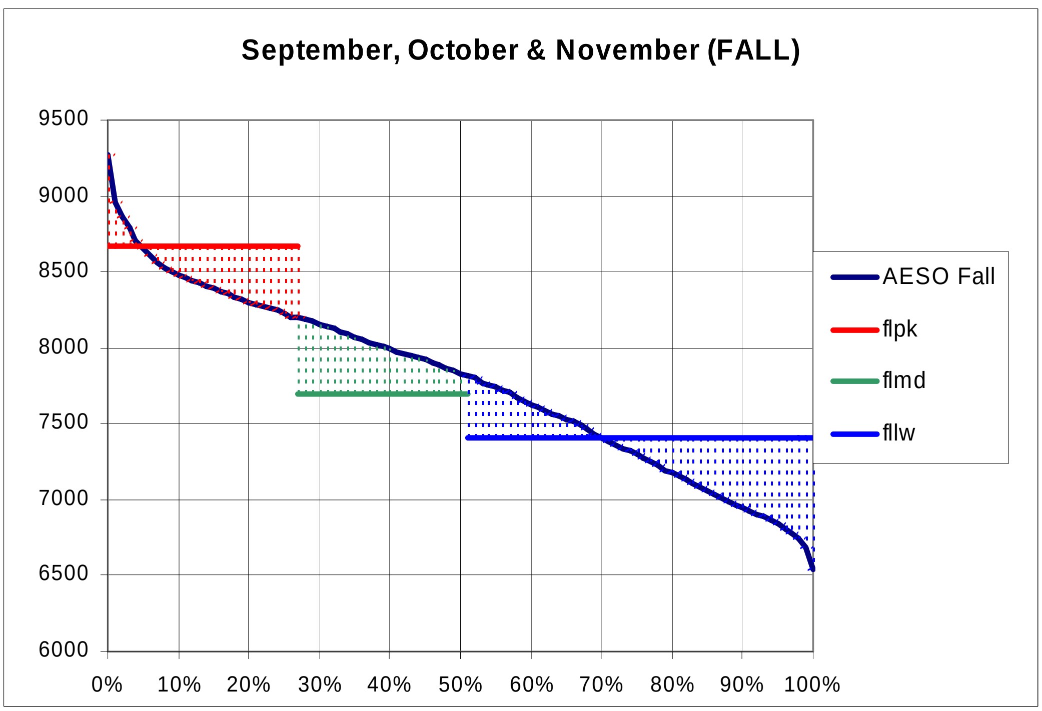


Figure 20 **Weightings Based on Fall Load Flow Levels**

THE POWER OF POSSIBILITY

Alberta Electric System Operator

Loss Factor Methodologies Evaluation Part 3
Loss Factor Compression

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada R3T 0P4

January 19, 2005
Revised January 26, 2005 **File No: 558-10000**

DISCLAIMER

This report was prepared under the supervision of Teshmont Consultants LP (“Teshmont”), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein. This report has been prepared exclusively for the Alberta Electric System Operator (AESO) and the project identified herein and must not be reused or modified without the prior written authorization of Teshmont. This report shall not be reproduced or distributed except in its entirety.

ALBERTA ELECTRIC SYSTEM OPERATOR

LOSS FACTOR METHODOLOGIES EVALUATION PART 2
CONVERSION OF Power to Energy Loss Factors

TABLE OF CONTENTS

Page

LOSS FACTOR METHODOLOGIES EVALUATION PART 2 CONVERSION OF POWER to Energy Loss Factors

1 Introduction

This report discusses the results of full system testing of methodologies to compress normalized loss factors to the regulation limits of plus 2 and minus 1 times the average system loss factor

2 Alternative Compression Approaches

2.1 Linear Compression

One methodology that is proposed to compress loss factors to the specified range is to apply a scaling factor to the loss factors of all generators to reduce the magnitude of the loss factors to the required limits. This process creates an energy balance error that must be compensated using a shift factor. Application of the shift factor may result in final loss factors outside the acceptable limits so the process may have to be repeated until an acceptable set of new loss factors are achieved.

This methodology is mathematically equivalent to rotating a vertical vector of loss factors (weighted by their volumes) around the average weighted loss factor for the system. The new loss factor becomes the vertical component of the rotated vector (divided by its weighting). Rotation continues until the largest positive new loss factor is less than twice the average system loss factor and the largest negative new loss factor is greater than the negative value of the average system loss factor.

Another mathematical equivalent of the linear compression approach is

1) Determine the average loss factor for the system
2) Select a scaling factor
3) For each generator, compute a compressed loss factor equal to the average system loss factor plus a new term equal to the scaling factor times the difference between the original loss factor and the average system loss factor

This linear compression algorithm is given by:

$$Lf_{average} = \frac{\Sigma Losses}{\Sigma Volumes} \qquad \text{Equation (1)}$$

$$Lf_{max} = 2 \cdot Lf_{average} \qquad \text{Equation (2)}$$

$$Lf_{min} = -Lf_{average} \qquad \text{Equation (3)}$$

$$K_{sf} = Max\left(Min\left(\frac{Lf_{max} - Lf_{average}}{Max\left(Lf_{original_i}\right) - Lf_{average}}, \frac{Lf_{min} - Lf_{average}}{Min\left(Lf_{original_i}\right) - Lf_{average}}, 1 \right), 0 \right) \qquad \text{Equation (4)}$$

$$Lf_{compressed_i} = Lf_{average} + \left(Lf_{original_i} - Lf_{average}\right) \cdot K_{sf}$$ Equation (5)

In equation (1) above, "$\Sigma Losses$" is the total system energy losses to be assigned, and "$\Sigma Volumes$" is the sum of the volumes of all generators for which the losses are to be assigned.

The term "$Max\left(Lf_{original_i}\right)$" represents the largest positive non-compressed loss factor of all generators.

The term "$Min\left(Lf_{original_i}\right)$" represents the largest negative non-compressed loss factor of all generators.

In equation (4), the lower limit of "0" is to prevent a situation where to solve the loss factor constraints, it is necessary to reverse the sign of the loss factors. If "K_{sf}" becomes zero, all generators in the system would be assigned the same compressed loss factor.

In equation (4), the upper limit of "1" is to used prevent a scaling factor of greater than 1. I.e. if the largest uncompressed positive and negative loss factors are within the limits, no compression will be applied.

Equation (5) above can be re-arranged to:

$$Lf_{compressed_i} = \left(1 - K_{sf}\right) \cdot Lf_{average} + K_{sf} \cdot Lf_{original_i}$$ Equation (6)

or:

$$Lf_{compressed_i} = K_{sf} \cdot Lf_{original_i} + ShiftFactor$$ Equation (7)

where:

$$ShiftFactor = \left(1 - K_{sf}\right) \cdot Lf_{average}$$ Equation (8)

A MathCAD implementation of the linear compression Algorithm is given in Figure 21.

Application of this methodology to the 2005 'winter' normalized loss factors calculated using the current swing bus methodology is shown in Figure 22. In the figure, loss factors, sorted from highest to lowest, are plotted against the cumulated energy volumes of all generators with loss factors greater than or equal to the individual generator loss factor. The total area between the loss factor curve and the 'X' axis of the curve is equivalent to the total energy losses of the system. The lower set of curves (b) is a repeat of the upper set (a) with an extended vertical scale.

Two loss factors curves are shown on each graph, depicting the original loss factors, and the loss factors for each generator after compression.

The compression method exhibits several undesirable traits. The majority of the loss factors are compressed to close to the average system loss factor, reducing any locational-based incentives for those units. In addition, loss factors of generators with large negative loss factors (or credits) with the original set of loss factors are compressed to values that are greater than the minimum permitted loss factor. This could be argued to be 'over-penalizing' these generators.

The compression of loss factors results in a significant shift in the responsibility for losses, from those generators with original loss factors greater than the system average, to those generators with original loss factors less than the system average.

2.2 Exponential Correction

In this method, the correction that is applied to the individual generator loss factor is exponentially weighted based on the magnitude of the difference between the original loss factor and the average system loss factor. A MathCAD implementation of the algorithm used is shown in Figure 23. Loss factors greater than average have different weightings than loss factors less than the average. The term "Lf_i-Lf_{av}" is essentially a 'gross' correction that is applied to each loss factor. If the exponential weighting factor is unity, no correction is applied. This occurs if the maximum loss factor is less than the maximum permitted (α is set to zero) or the minimum loss factor is greater than the minimum permitted (β is set to zero).

Once loss factors are compressed, a shift factor is applied to correct the loss energy balance and linear compression is then applied to restore any new violations resulting from application of the shift factor to within the limits.

Application of this methodology is shown in Figure 24. While this methodology has less impact on generators with loss factors within the defined range, and the degree of 'over-penalizing' of generators with large negative loss factors is less than the linear compression methodology it has an undesirable, (almost unacceptable trait) it that after compression, the resultant loss factors are no-longer monotonically decreasing. This is evident in curve b of the figure in the high loss factor range where cumulated energy is less than about 1 GWh.

2.3 Exponential Compression

In this method the compressed loss factor is a simple exponential function of the original loss factor. A MathCAD implementation is shown in Figure 25, and the impact on loss factors is shown in Figure 26. With this algorithm it is necessary to adjust the constants k_1 and k_2 to insure compression of the large loss factors while limiting the impact on loss factors within range and maintaining monotonically decreasing loss factors.

The values of constants used for the compression shown in the figure are:

$$k_1 := -.05$$

$$k_2 := .11$$

With these constants, large loss factors are monotonically compressed, with reduced impact on loss factors within range and with the largest and smallest (most negative) loss factors compressed to the extremes directed by the board.

For this demonstration, the constants have been selected on a trial and error basis. It should be possible to establish a mathematical criterion for the selection of the constants for a production version of the algorithm.

2.4 Clipping Plus Linear Compression

In this algorithm, loss factors are limited to the maximum permitted values, a shift factor is applied to the set of loss factors not originally at the limit to balance the energy loss, and linear compression is applied to the reduced set of loss factors to restore loss factors (forced out of range by the shift factor) to the stated limits.

A MathCAD implementation of the clipping algorithm is shown in Figure 27. The impact on loss factors is shown in Figure 28.

The methodology has the advantage that:

- loss factors originally within the range are not significantly affected by the the compression.
- loss factors that were originally clipped are neither further credited nor penalized.

2.5 Recursive Clipping

This methodology involves a recursive application of loss factor clipping followed by shift factor correction to the remaining generators until the loss factors are all within limits and the energy loss balance is obtained.

A MathCAD implementation of the clipping algorithm is shown in Figure 29 and its impact on loss factors is shown in Figure 30.

The final loss factors are very close to the loss factors obtained with clipping followed by linear compression. The main difference is that no loss factors are changed from values outside the limits to new values within the limits. Again the impact on generators originally within the limits is small.

3 Comparison of Methodologies

The five methodologies discussed above can be grouped into three categories namely linear compression, exponential compression and clipping. Within each category the impact of compression on losses is similar. The three categories are compared in Figure 31. In the upper figure, loss factors are plotted against the accumulated energy providing a visual assessment of the compression methodology on energy. In the lower figure, the loss factors are plotted against the generator number giving a visual assessment of the number of generators affected by the methodology.

Figure 32 shows the impact of compression methodology to the amount of losses allocated to each generator.

Figure 33 shows the cumulated change in energy allocation of each methodology and is representative of the total swing in energy loss allocation resulting from each of the compression methodologies.

Linear compression not only involves the largest shift in energy allocation but also significantly affects the largest number of generators.

Exponential compression has less impact than linear compression in that fewer generators are significantly impacted and less shift in energy allocation is involved.

Clipping primarily affects only those few generators outside of the limits.

4 Sensitivity to Range of Loss Factors

Preliminary investigations using the 50% area load adjustment methodology suggested in [1] indicate that the loss factors for almost all of the generators in the Alberta system will fall within the maximum permitted range of loss factors. Even though the majority of loss factors are presently within the range, changes to the transmission network and changes to system dispatch in the future may result in loss factors being slightly outside the specified range.

Each of the three categories of methodologies was tested for this sensitivity. All of the normalized loss factors calculated with the present swing bus methodology were arbitrarily reduced by a factor of two and an additional shift factor introduced to restore the energy loss balance. The comparisons are shown in Figure 34, Figure 35 and Figure 36.
This sensitivity study shows that with original loss factors that are outside but closer to the limits, the behaviour of the exponential compression methodology changes. Loss factors continue to decrease monotonically, i.e., the ranking of generators by loss factor does not change. However, for some generators, the loss factor is increased, while for others, the loss factor is reduced. This is not unexpected as there is always a shift required to balance the energy loss equation. However, to reflect the objectives of the regulations, the general characteristics of the loss factor variation curves should at least be similar to those exhibited by linear compression methodology, which does reflect the stated objectives. Those generators receiving credits with linear compression should receive credits for all methodologies.

This is particularly evident in Figure 35 and Figure 36. Generators ranked from about 12 to 25 are penalized by the exponential compression method. With linear compression, however, their loss factors are improved. Similarly generators ranked above about 60 are credited with the exponential compression methodology and penalized with the linear compression method.

For the clipping methodologies, there will also be a few generators with loss factor changes that are in the opposite direction to that of the linear compression methodology. However, this would only apply to generators with loss factors that were originally close to zero.

5 Recommendations

The exponential correction algorithm is unattractive as it will over-compress loss factors at the extremities of loss factor range.

Exponential compression is unattractive since it requires a judicious selection of compression gains and could be a source for loss factor manipulation.

Linear compression is unattractive as resultant loss factors are extremely sensitive to small generators with large positive or negative loss factors. A small generator with a large loss factor will compress all loss factors to close to the system average loss factor. Locational based generating signals will be lost.

Both recursive clipping and clipping with linear compression have minimal impact on loss factors within limits for conditions with small generators outside of limits. If a situation does arise where a large generator with a large loss factor (positive or negative) exists, the algorithm with clipping and linear compression will have fewer units forced to limits by the requisite shift factor.

On this basis it is recommended that the ‘clipping with linear compression algorithm’ be used to compress loss factors. The methodology limits the magnitude of loss factors without significantly shifting the assignment of losses. For the expected situation where all loss factors are expected to be within limits, compression will not be required. However if a situation does arise where a small generator is added to the system at an unfavourable location or network configuration changes such that the loss factor of a small generator changes to a large positive or negative value, minimal shift in responsibility for losses occurs. If a similar situation arises but the generator capacity is large, a large shift in loss allocation is required, however, the loss factors of the other generators will retain their overall ranking.

6 References

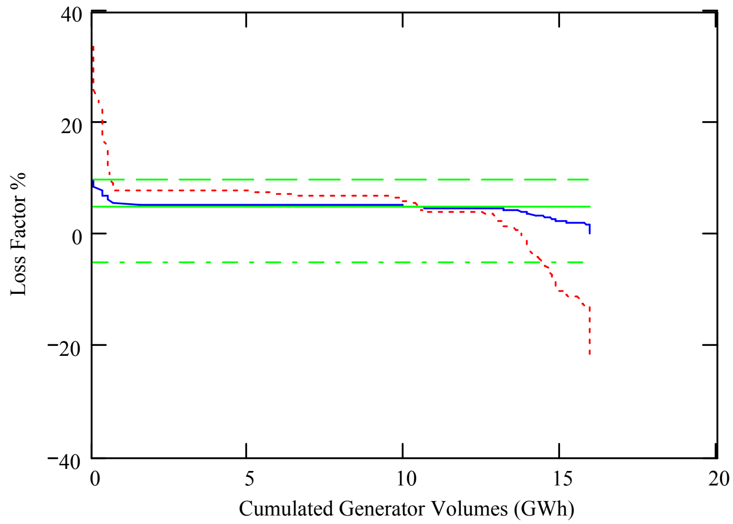
[1] Report ‘Loss Factor Methodologies Evaluation Part 1 - Determination of ‘Raw’ Loss Factors” prepared by Teshmont Consultants LP, Revised December 22, 2004.

Method 1 Linear Compression plus shift factor

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

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 wthat when multiplied by the average loss factor defines the minimum permitted loss factor

Figure 21 MathCAD Implementation of Linear Compression Algorithm



(a)

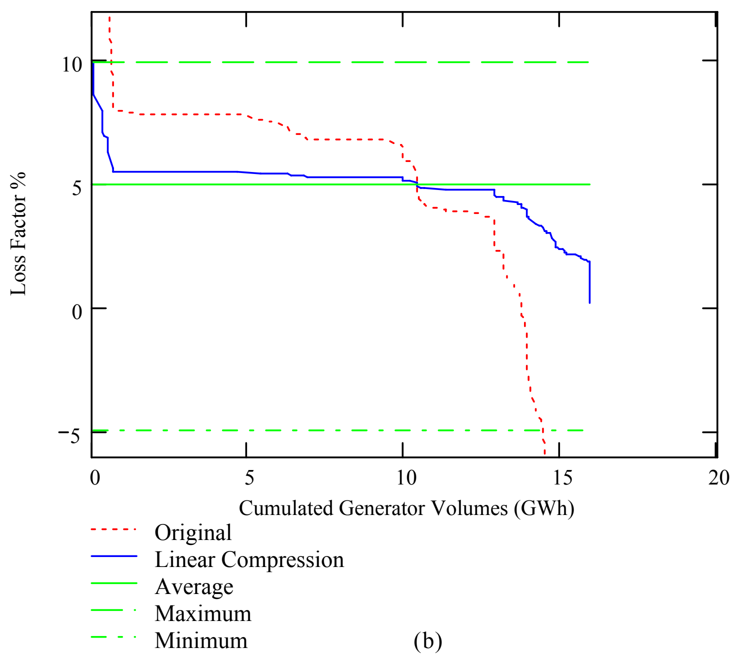


Figure 22 Impact of Linear Compression on Loss Factors

Method 2 correction to actual loss factor based on exponential weighting, plus linear compression after adjustment for energy

$$
Lf_2(Lf, E, k_{max}, k_{min}) := \left|
\begin{array}{l}
Losses \leftarrow (Lf)^T \cdot E \\
Lf_{av} \leftarrow \dfrac{Losses}{Sum(E)} \\
Lf_{max} \leftarrow k_{max} \cdot Lf_{av} \\
Lf_{min} \leftarrow k_{min} \cdot Lf_{av} \\
\alpha \leftarrow \left| \begin{array}{l} max_{lf} \leftarrow max(Lf) \\ 0 \ \text{ if } \ max_{lf} < Lf_{max} \\ \dfrac{\ln\left(\dfrac{Lf_{max} - Lf_{av}}{max_{lf} - Lf_{av}}\right)}{max_{lf} - Lf_{av}} \ \text{ otherwise} \end{array} \right. \\
\beta \leftarrow \left| \begin{array}{l} min_{lf} \leftarrow min(Lf) \\ 0 \ \text{ if } \ min_{lf} > Lf_{min} \\ \dfrac{\ln\left(\dfrac{Lf_{min} - Lf_{av}}{min_{lf} - Lf_{av}}\right)}{min_{lf} - Lf_{av}} \ \text{ otherwise} \end{array} \right. \\
\text{for } \ i \in 0..\, rows(Lf) - 1 \\
\quad Lf_{2a_i} \leftarrow Lf_{av} + e^{\left[\left| \begin{array}{ll} \alpha \cdot (Lf_i - Lf_{av}) & \text{if } Lf_i > Lf_{av} \\ \beta \cdot (Lf_i - Lf_{av}) & \text{otherwise} \end{array} \right. \right]} \cdot (Lf_i - Lf_{av}) \\
Lf_2 \leftarrow Lf_{2a} + \dfrac{\left(Losses - {Lf_{2a}}^T \cdot E\right)}{Sum(E)} \\
Lf_2 \leftarrow Lf_1(Lf_2, E, k_{max}, k_{min})
\end{array}
\right.
$$

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 wthat when multiplied by the average loss factor defines the minimum permitted loss factor

Figure 23 MathCAD Implementation of Exponential Correction Algorithm

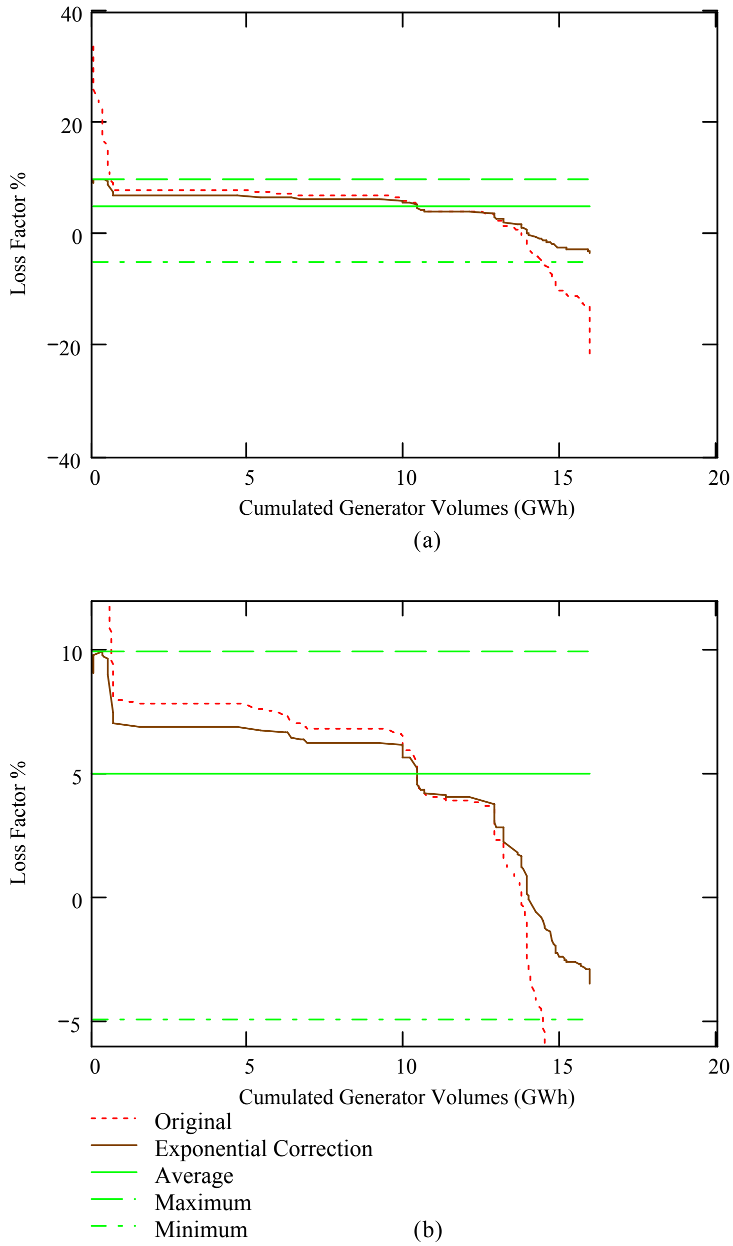


Figure 24 Impact of Exponential Correction Algorithm on Loss Factors

Method 3 Exponential Weighting Plus Linear Compression

$$
Lf_3(Lf, E, k_{max}, k_{min}, k_1, k_2) := \left|
\begin{array}{l}
Losses \leftarrow (Lf)^T \cdot E \\
Lf_{av} \leftarrow \dfrac{Losses}{Sum(E)} \\
Lf_{max} \leftarrow k_{max} \cdot Lf_{av} \\
Lf_{min} \leftarrow k_{min} \cdot Lf_{av} \\
\alpha \leftarrow \left|
\begin{array}{l}
max_{lf} \leftarrow max(Lf) \\
0 \ \text{ if } \ max_{lf} < Lf_{max} \\
\dfrac{\ln\left(1 + \dfrac{Lf_{max} - Lf_{av}}{k_1}\right)}{max_{lf} - Lf_{av}} \ \text{ otherwise}
\end{array}
\right. \\
\beta \leftarrow \left|
\begin{array}{l}
min_{lf} \leftarrow min(Lf) \\
0 \ \text{ if } \ min_{lf} > Lf_{min} \\
\dfrac{\ln\left(1 + \dfrac{Lf_{min} - Lf_{av}}{k_2}\right)}{min(Lf) - Lf_{av}} \ \text{ otherwise}
\end{array}
\right. \\
\text{for } \ i \in 0..\, rows(Lf) - 1 \\
\quad Lf_{3a_i} \leftarrow Lf_{av} + \left[\left|
\begin{array}{l}
k_1 \cdot \left[e^{\left[\alpha \cdot \left(Lf_i - Lf_{av}\right)\right]} - 1 \right] \ \text{ if } \ Lf_i > Lf_{av} \\
k_2 \cdot \left[e^{\left[\beta \cdot \left(Lf_i - Lf_{av}\right)\right]} - 1 \right] \ \text{ otherwise}
\end{array}
\right. \right] \\
Lf_3 \leftarrow Lf_{3a} \\
Lf_3
\end{array}
\right.
$$

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 wthat when multiplied by the average loss factor defines the minimum permitted loss factor
k_1 is a factor applied to the exponent of loss factors greater than the average
k_2 is a factor applied to the exponent of loss factors less than the average

Figure 25 MathCAD Implementation of Exponential Compression Algorithm

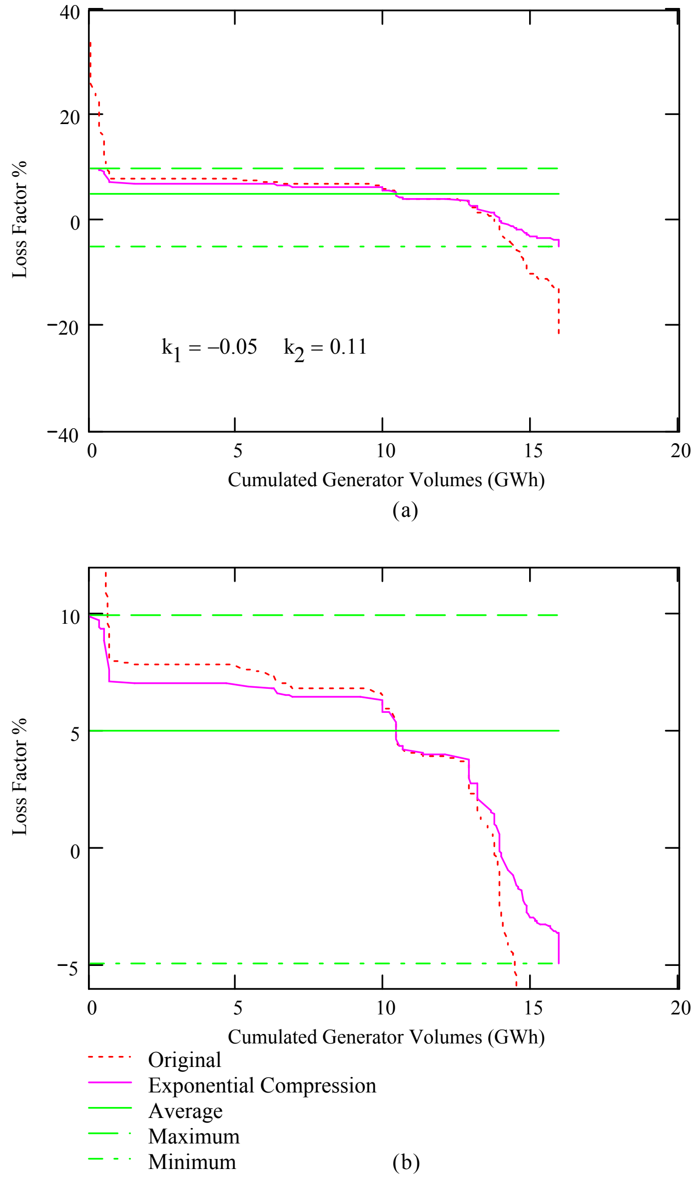


Figure 26 Impact of Exponential Compression Algorithm on Loss Factors

Method 4 Clipping Plus Linear Compression

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

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 wthat when multiplied by the average loss factor defines the minimum permitted loss factor

Figure 27 MathCAD Implementation of Clipping With Linear Compression Algorithm

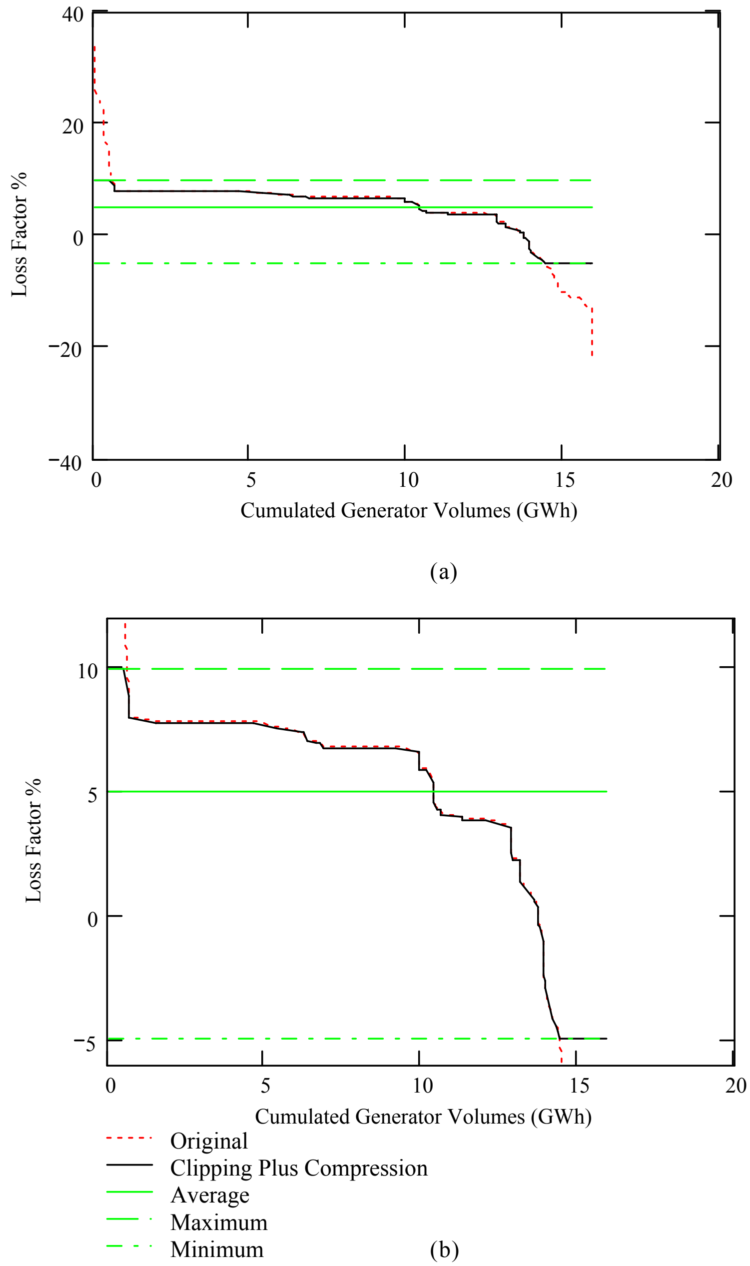


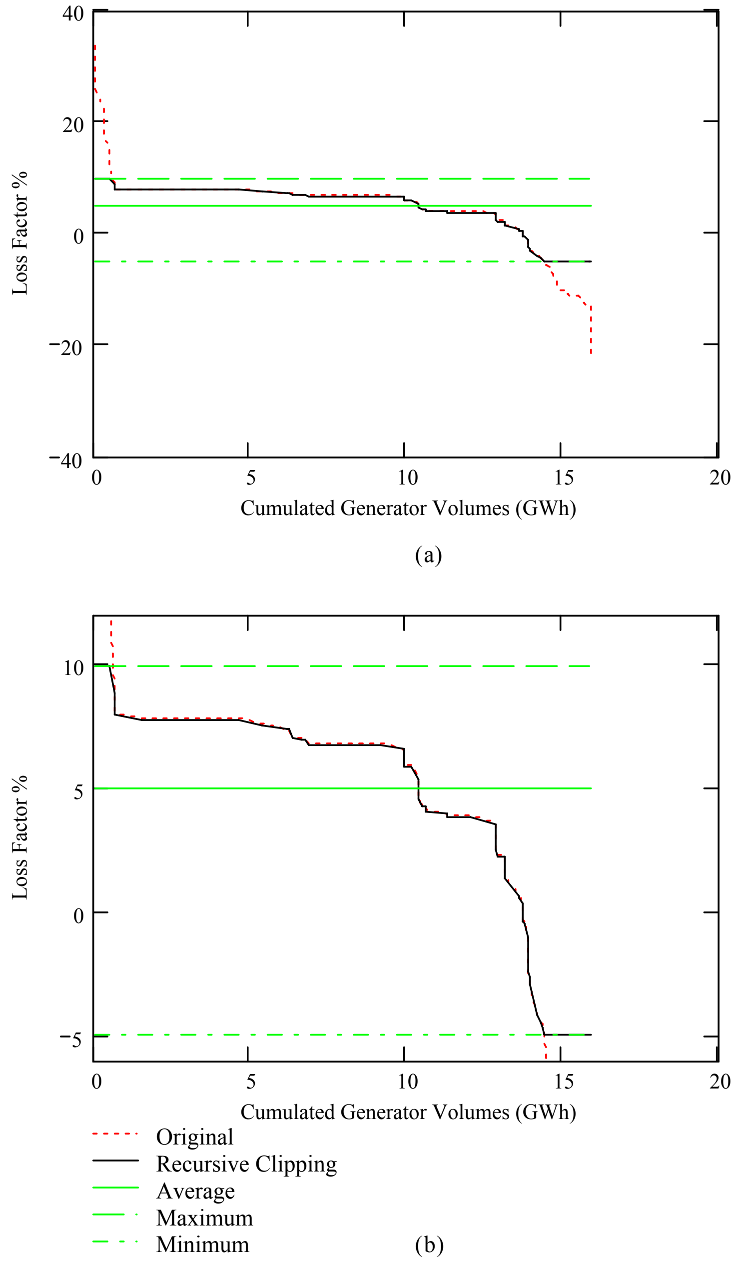
Figure 28 Impact of Clipping With Linear Compression Algorithm on Loss Factors

Method 5 Recursive clipping plus shift factor

```
Lf5(Lf, E, k_max, k_min) := | count_max ← 50
                            | toler ← .00001%
                            | Losses ← Lf^T·E
                            | Lf_av ← Losses / Sum(E)
                            | Lf_max ← k_max·Lf_av
                            | Lf_min ← k_min·Lf_av
                            | i_max ← (rows(Lf) − 1)
                            | lf ← Lf
                            | count ← 0
                            | δ ← max(Lf) > (Lf_max + toler) ∨ min(Lf) < (Lf_min − toler%)
                            | while count < count_max ∧ δ
                            |    | lf ← for i ∈ 0.. i_max
                            |    |          | lf_i ← max(min(lf_i, Lf_max), Lf_min)
                            |    |          | lf
                            |    | SumE ← | SumE ← 0
                            |    |        | for i ∈ 0.. i_max
                            |    |        |    SumE ← SumE + E_i  if  lf_i < Lf_max ∧ lf_i > Lf_min
                            |    | sf ← (Losses − lf^T·E) / SumE
                            |    | lf ← | for i ∈ 0.. i_max
                            |    |      |    lf_i ← lf_i + sf  if  lf_i < Lf_max ∧ lf_i > Lf_min
                            |    |      | lf
                            |    | δ ← | δ ← max(lf) > (Lf_max + toler) ∨ min(lf) < (Lf_min − toler%)
                            |    |     | δ ← δ ∧ sf ≥ 0
                            |    | count ← count + 1
                            | lf
```

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 wthat when multiplied by the average loss factor defines the minimum permitted loss factor

Figure 29 MathCAD Implementation of Recursive Clipping



Algorithm

Figure 30 Impact of Recursive Clipping Algorithm on Loss Factors

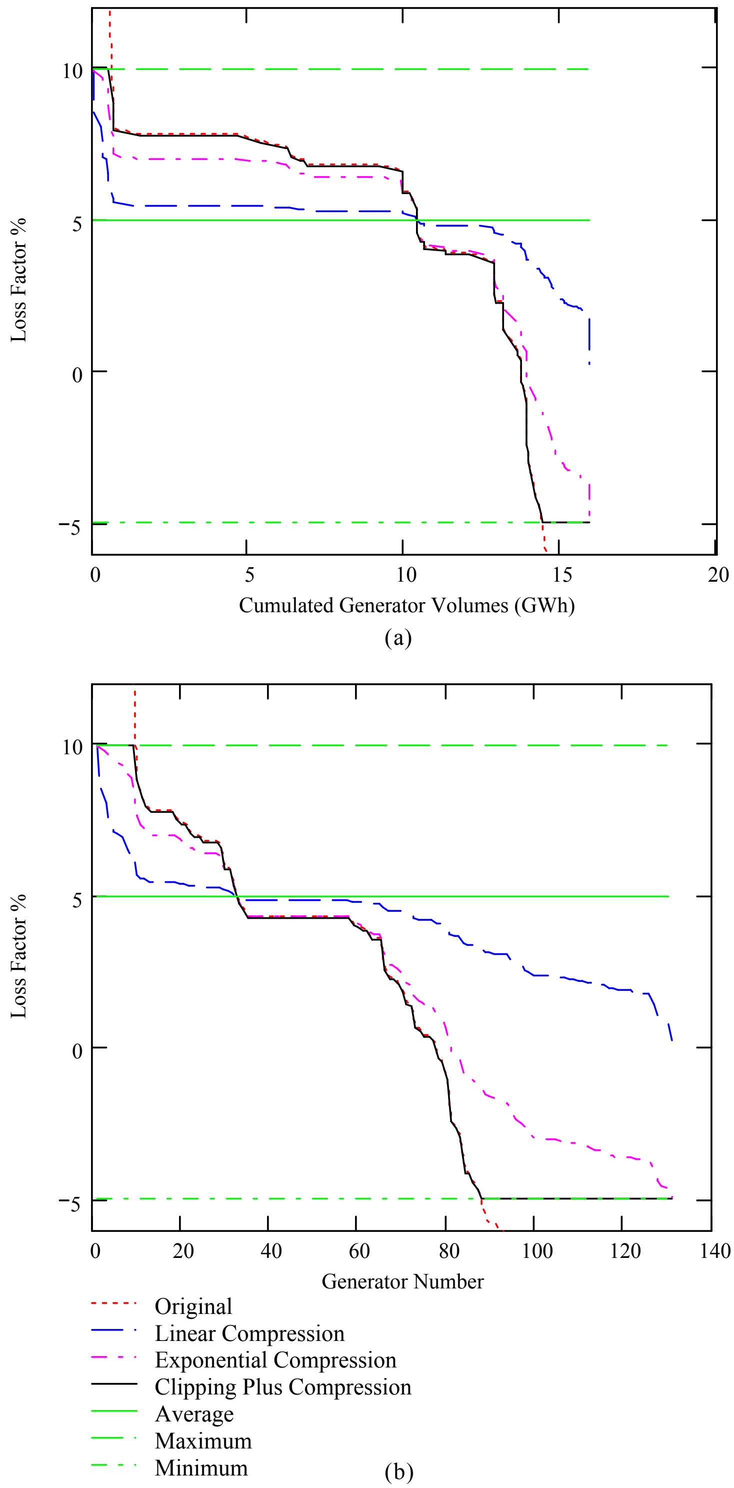


Figure 31 Comparison of Impact on Loss Factors

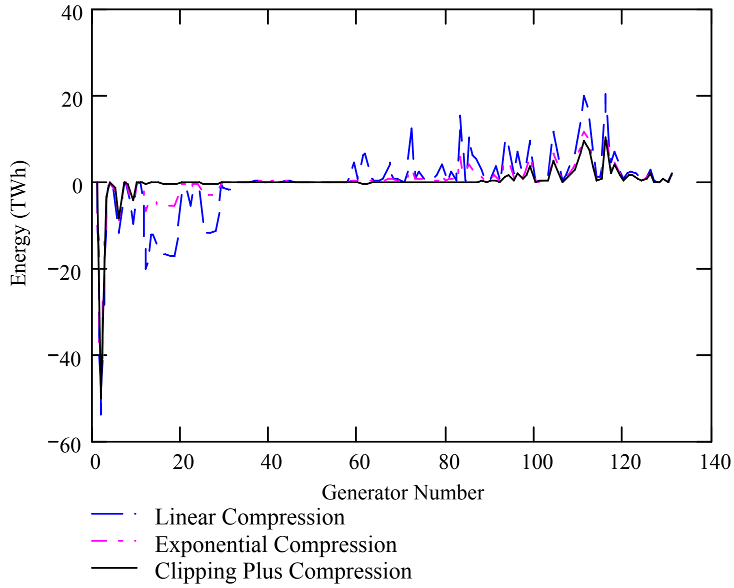


Figure 32 Changes in Individual Generator Loss Allocation

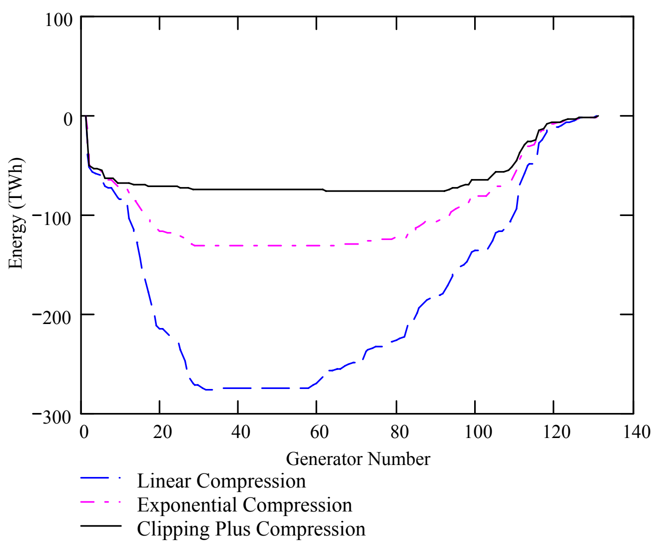
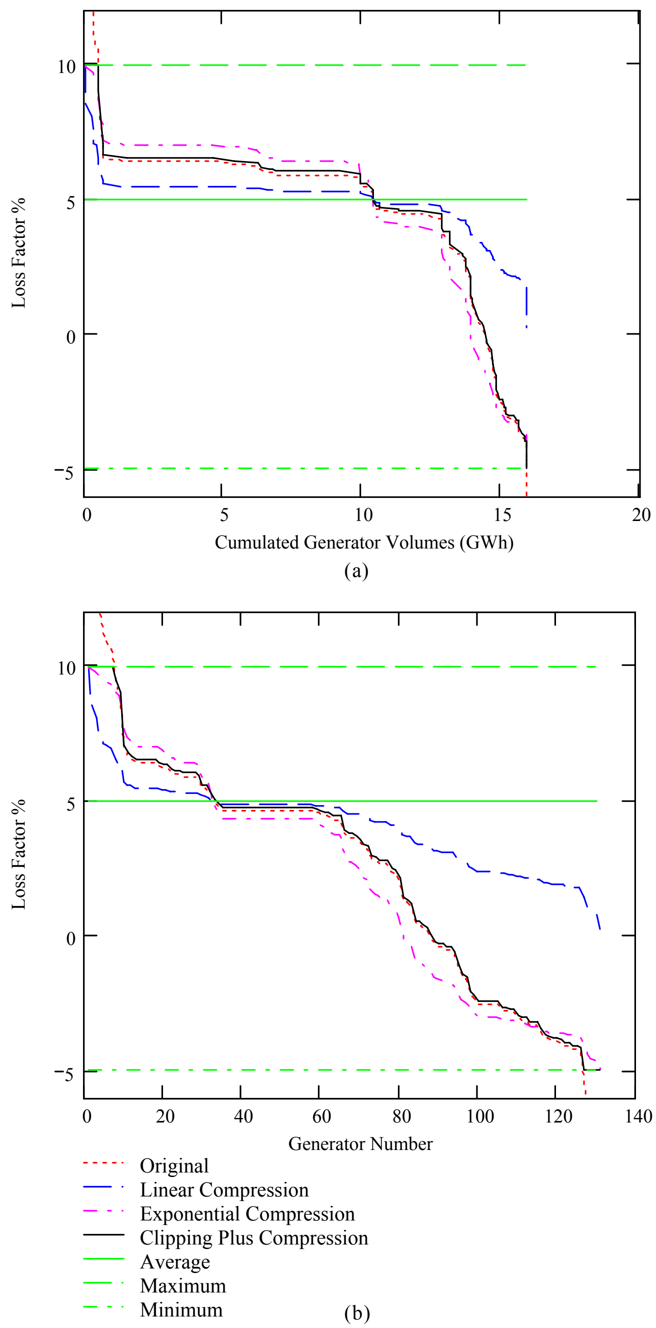


Figure 33 Cummulative Change in Generator Loss



location

Figure 34 Comparison of Impact on Loss Factors Sensitivity to Smaller Magnitude Initial Loss Factors

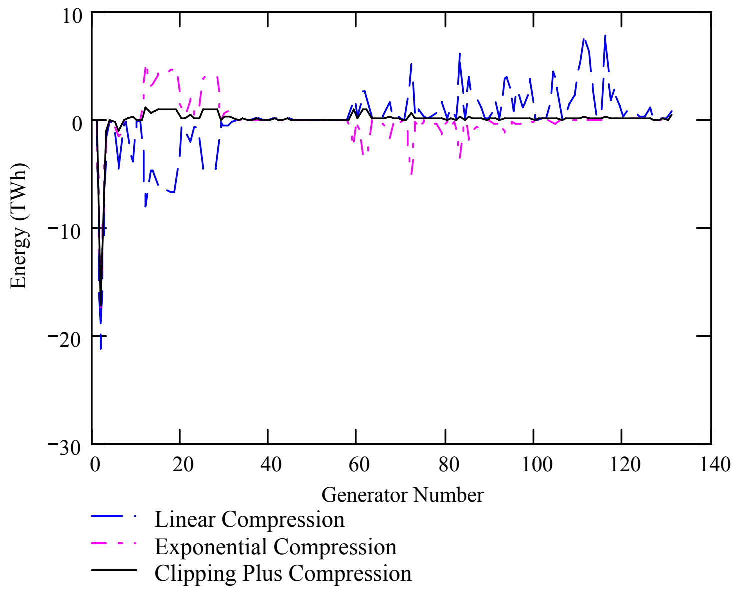


Figure 35 Changes in Individual Generator Loss Allocation Sensitivity to Smaller Magnitude Initial Loss Factors

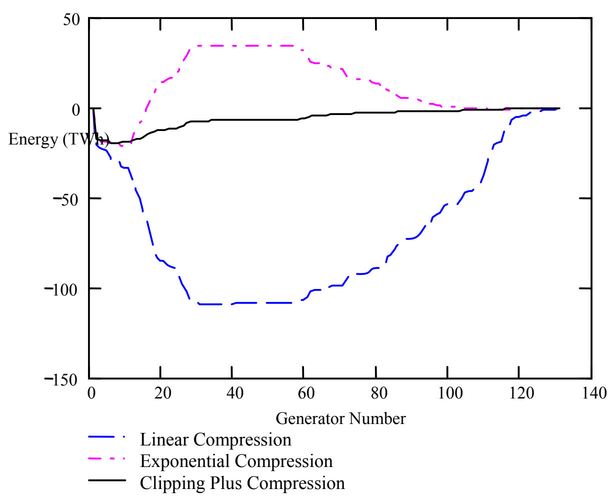


Figure 36 Cummulative Change in Generator Loss Allocation Sensitivity to Smaller Magnitude Initial Loss Factors

Alberta Electric System Operator

Loss Factor Methodologies Evaluation – Determination of Opportunity Services "Raw" Loss Factors

Teshmont Consultants LP
1190 Waverley Street
Winnipeg, Manitoba
Canada R3T 0P4