AESO has combined the two documents from Calpine Dated April 27, 2005. AESO responses are in bold.

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Calpine Document 1

April 25, 2005

Hi Rob:

As you requested in the April 12 meeting I am enclosing additional Calpine concerns with respect to the selection and application of the loss factor methodology.

Calpine concerns fall into two general areas:

1. Concerns related to impact of new loss factors. This is essentially tariff concern
2. Concerns related to the methodology and whether it fulfills the objectives set for loss factors in Trasmission Regulations.

1 1 Tariff concerns

Calpine concurs with the AESO's explanation during the April 12th meeting that the outcome of the loss factor methodology, i.e. the loss factors charges, is effectively tariff and as such it should follow sound rate design principles. Calpine also concurs with the AESO that the methodology used in deriving the loss factor charges may differ from methodologies that are commonly used in rate design.

Concesequently, Calpine believes that the loss factor charges should comply with generally accepted "attributes of sound rate structure". These attributes have been summarized and documented in the Bonbright's Principles of Public Utility Rates and have been accepted in Alberta and elsewhere as the basic measure for appropriate rate design and for rate structure evaluation. In fact, these principles are often directly cited in the GTA submissions.

Calpine is concerned that the AESO's proposed loss factor methodology does not follow at least the following Bonbright's Principles:
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1. Attribute No3: “Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity”

2. Attribute No4: “Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified type and amounts of use”.

3. Attribute No5: Reflection of all of the present and future private and social costs and benefits occasioned by a service’s provision (i.e. all internalities and externalities).

4. Attribute No6: Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e. equals treated equally), (2) vertical (i.e. unequals treated unequally and (3) anonymous (i.e. no ratepayer’s demand can be diverted away uneconomically from an incumbent by a potential entrant).

5. Attribute No7: Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e. subsidy free with no intercustomer burdens)

Each of the above principles is further discussed in the following paragraphs.

Attribute No3:

AESO’s proposed loss factors constitute a large change in rates. In the absence of any phase in period, all the changes will take place in 2006 when new loss factors will come to an effect. The AESO has shown that the expected changes are large; for number of generators the increase can reach 16% of the pool price. At an average pool price of $50 per MWh this represents over $8 per MWh. This in turn corresponds to over 300% change in rate (increase) when compared to basic per MWh interconnection charge (2.62$/MWh). Of course, the increase in rate is even higher during the high load periods when pool price is higher.

Attribute No4:

By not fully representing the impact of each generator on average system losses, the loss factor charges do not promote efficiency and encourage wasteful use of transmission service.

The proposed loss factors effectively (when compared to the previous loss factors) discourage generation that reduces system losses while it encourages generation in the areas that contribute to high system losses; both in real time (generation dispatch) and in terms of signal for optimal generation siting.

Attribute No:5

The new loss factors do not reflect all of the present and future private and social costs.

Firstly, the loss factors do not fully reflect the impact generators have on average system losses. Based on AESO's explanation of new loss factors, the loss factors represent approximately one half of such impact (loss factor charges being slightly more than half while loss factor credits being less than half of generator's impact on average system losses). Calpine own preliminary analysis suggests that the difference between generator's impact on average system losses and the loss factor charge is much higher; in Calpine case fourteen times – loss factor is <u>14 times smaller</u> than the impact on average system losses.

Such approach contradicts not only the test of sound rate structure but also AESO very own approach towards need justification for new transmission facility. In the recent Edmonton to Calgary 500kV Need application, AESO argued that loss reduction is one of the primary justifications for the proposed upgrades. In that approach, AESO has used 100% of marginal loss reduction.

Attribute No:6

The fairness issue of "equals being treated equally" has been recognized by ADOE by prescribing that generators with the same impact on average system losses receive the same loss factor. It would be logical to expect that generators that have the same magnitude of impact on average system losses but one causes an increase while other causes decrease will receive loss factors of the same magnitude and opposite sign. This is not the case. In the AESO's approach, generator that reduces system losses will be penalized compared to a generator that increases system losses.

Atribute No:7:

New loss factors introduce large cross-subsidy where generators that contribute to loss reduction cross-subsidize generators that most contribute to system losses.

2 2 Methodology concerns

2.1 Transmission Regulations Concerns

Calpine is concerned that the proposed loss factors do not "reflect the impact generator has on average system losses" as prescribed by Transmission Regulations. Furthermore, in certain cases, the loss factors derived from the proposed methodology fails 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.

These concerns are further discussed in the next three sections.

2.1.1 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.

2.1.2 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).

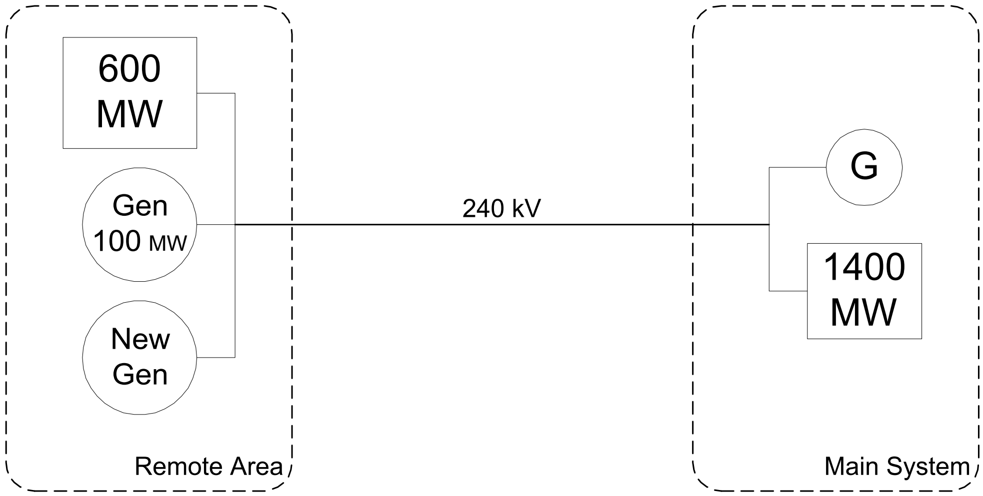

Figure 1 Example system 1

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:

1. 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.

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

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

2.1.3 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:

1. two generators that increase or decrease system average losses equally should have the same loss factor and

2. 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 2).

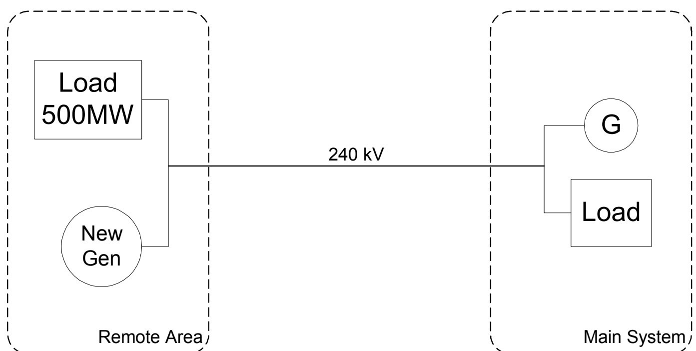

Figure 2: Symmetry example System

Figure 3 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[1].

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 4.

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

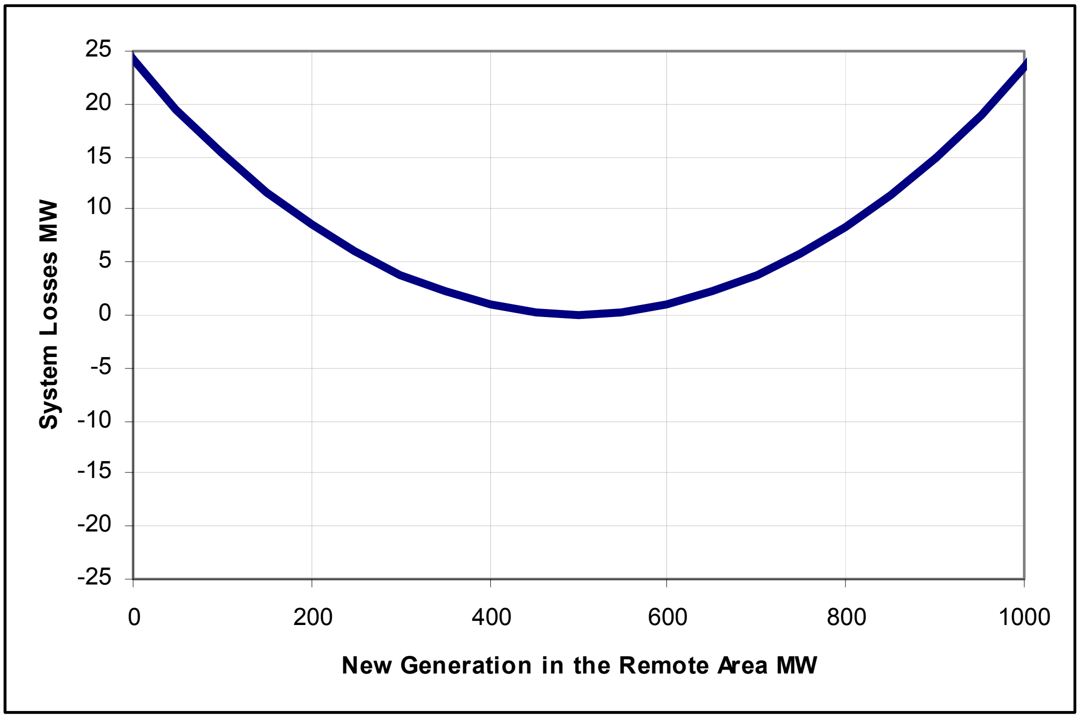

Figure 3: System Losses for Example System 1

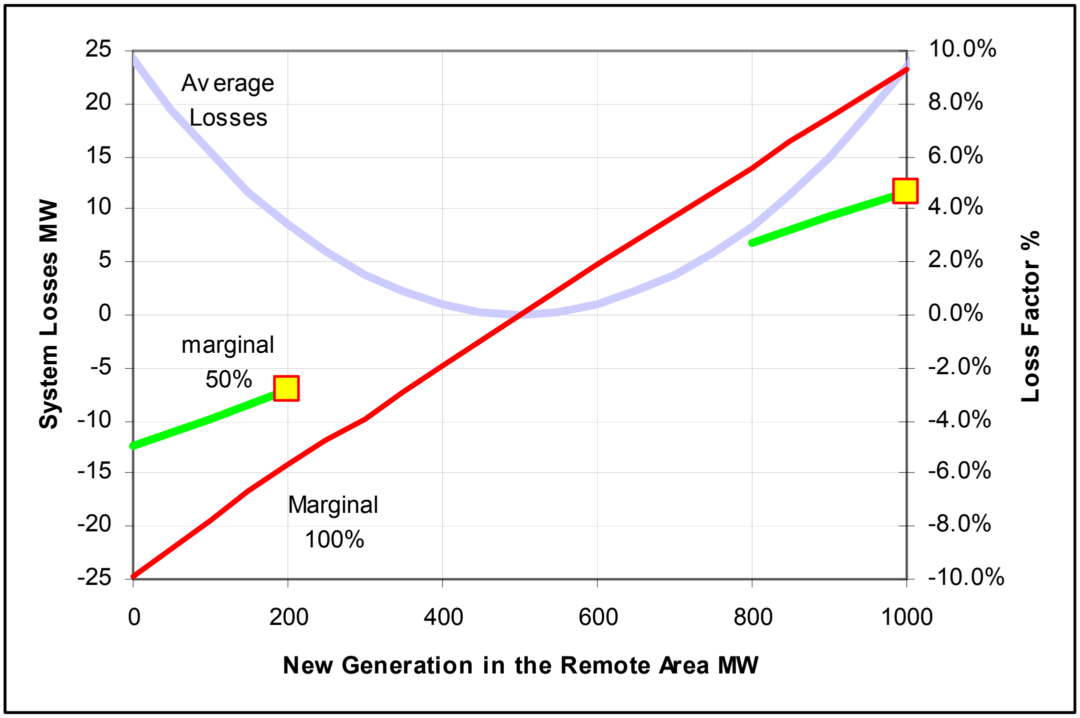

Figure 4: Marginal Loss Factor as proposed (with swing bus)

2.2 Impact of new methodology on system losses

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.

Q1. Calpine respectfully requests that AESO addresses this issue in detal prior to the adoption of the methodology.

A1. Ans. 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 generating unit locations than loss factors.

2.3 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.

AESO Comment: AESO has addressed many issues (the two bus issue, the equality/fairness issue, and so on) in the past number of months through the course of our methodology review and subsequent stakeholder question meetings. Loss factors are being determined through principles governed by the 2004 transmission regulation. For Calpine to state, for example, a generator should receive a 16% credit is really not helpful. The transmission regulation limits loss factor credits to one times system average losses. The proposed methodology does not apply a 50% shift factor. In fact the methodology calculates incremental losses and divides the result by two which produces average losses. This is consistent with the transmission regulation s.19 (2) (d). The AESO has also provided evidence that incremental losses divided by 2 equals average losses. Additionally, AESO agrees with Teshmont that their methodology review assessment of loss factors demonstrates that the proposed methodology meets the spirit and intent of the regulation.

Further, AESO has not agreed that loss factor determination is a tariff issue. 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.

<u>Calpine Document 2</u>

Calpine has following comments to the Transmission Loss Factor Rule 11-04-05

Page 2:

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

Q2. Please define what is the AESO interpretation of "long-term signal"

A2. A long term signal determines a facilities loss factor that would remain in effect until changes on the system or in the asset causes a loss factor to change. Any change in loss factors would also reflect long term pricing signals (average loss factors clipped to a three times system average) as opposed to short term pricing signals reflected by marginal unclipped loss factors.

Q3. Please define what is the AESO's interpretation of "relatively stable"

A3. Stability in this context means no significant change will occur to losses or loss factors due to changes in growth and normal generating unit additions in Alberta. A significant change to loss factors overall will only occur with a significant change to the system topology such as the addition of a large 500 kV circuit from Edmonton to Calgary.

Page 3:

A market participant 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.

Q4. Given AESO's indication during the April 12th meeting that import and export loss factors will be subjected to the same bandwith as the generators in the province, is the statement still correct?

A4. Yes.

Calpine has following comments to the “Transmission Loss Factor Methodology And Assumptions Appendix 8” (March 9, 2005)

Page 3:

> *Generators not represented in the ‘historical’ load flow model but which would be in merit according to the stacking order will be assumed to be on maintenance or forced outage. Generators modeled in the load flow but not in merit according to the historical load flow will be assumed to be generating according to market conditions, and will continue to be operated at their base case values.*

Q5. Please reconcile the above statement with discussion during the meeting on April 12 and prior where AESO confirmed that all generating units will be dispatched as per the relevant stacking order (both sequence and output levels).
A5. AESO has modified the rule to accommodate the new information.

Consequently, the actual dispatch in the particular 12 historical cases serving as a source for development of the loss factor cases is not relevant.

Please correct the wording or explain the discrepancy.

Page 6:

> *Any new generators for which a historical record is not available will be dispatched according to the ISO’s analysis of the generator technology. Its power output would be based on its Incapability Factor. Industrial system generation and hydro generation to be re-dispatched accordingly.*

Q6. Please describe where will be obtained “Incapability Factor”, how it will be updated from year to year and how will be decided the type of generator (i.e. what will be the grouping).
A6. For units new to the system, AESO will use the latest CEA data for outage rates. Location of the new unit within the GSO will be by type (coal, hydro, gas, etc) and arranged by historical price as the data becomes available.