

ALBERTA UTILITIES COMMISSION

Application No. 1606494

Proceeding ID 790

**Complaint by Milner Power Inc. Dated August 17, 2005 Regarding
Transmission Loss Factor Rule and Loss Factor Methodology**

WRITTEN EVIDENCE OF

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ON BEHALF OF

MILNER POWER INC.

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THE APPROXIMATELY \$100 MILLION of potential production cost savings from implementing MARGINAL LOSSES is a result of ... [the fact that] the dispatch will change to minimize the losses ... thereby resulting in reduced production cost.
PJM, Marginal Loss Implementation FAQs, 2007

5 1. Introduction and Summary

Context for the Evidence

The following report comprises the evidence of Dr. Steven Stoft filed on behalf of Milner Power Inc. Milner in Alberta Utilities Commission Proceeding ID 790. This evidence is intended to supplement Milner's August 17, 2005 Complaint, and looks in particular at the economic reasonableness of the R-bus 50% Area Loss Factor Methodology. This report includes appendices which provide additional analysis on some points. Milner has also requested that I respond to a recent filing by the AESO, Bus Test System Report on Loss Factor Methodology, dated March 9, 2011, which was prepared in response to a request made by TransCanada Energy Ltd. My response to this filing is set out in Appendix 3.

Summary of Evidence

In summary, this evidence finds as follows:

1. (R-# ± ... / prices transmission services at one-half of marginal cost by multiplying standard Marginal Loss Factors by 50%. Consequently, will be referred to as MLF/2.
2. From at least 2005 until the present, the AESO and its consultant, Teshmont, have misunderstood the method of calculating price signals, and consequently have arrived at signal values that are quite often extremely inappropriate. Their mistake has been to interpret a pair of loss charges at different locations as a price signal for investment. This is only correct for infinitely small investments that do not affect loss factors at either location. However, they have used this approximation when the impact on loss factors is

dramatic, implicitly assuming that investors are unaware of the impact of their own investments.

3. Basic economic theory, standard texts in the field of power system economics, and five major U.S. power markets all agree that dividing the marginal loss factors (MDF) by two distorts price signals and causes the market to perform inefficiently. This increases costs of generation and transmission, costs which are generally passed through to consumers. Since *not* dividing by two is a simple matter, it would appear unreasonable for the AESO to persist in this mistake.¹ It was also unreasonable that it introduced this mistake in 2005.
4. Although marginal-cost pricing is a matter of basic economic theory, somewhat more advanced theory indicates that when decisions are not marginal, marginal-cost pricing is not optimal. In fact, generation investment is an incremental rather than a marginal decision and when it takes place in a relatively isolated part of the system, it can be quite far from marginal. Because of this, some form of incremental loss factors will improve locational signals significantly in remote areas, and will most likely be beneficial as a general replacement for marginal loss factors.

Recommendations

Based on the analysis and the evidence presented, the following are my key recommendations:

1. The AESO should not divide raw loss factors by two but rather shift them all by the same amount and the amount necessary to achieve the desired revenue collection.
2. The AESO should replace marginal loss factors with an incremental loss factor approach.

¹ Note that the AESO is already using a shift factor. Eliminating division by two would change that factor, but it would not add any new calculation to the present method.

2. An Economic Approach to an Economic Problem

An Economic Problem

The purpose of computing loss factors such as the R-bus 50% Area Loss Factors used by the AESO is to charge for losses. These factors are not used to dispatch the system or for any engineering purpose. Charging for losses is a problem in economics: it is not an engineering problem. Unfortunately, this economics problem has been solved by the AESO without the use of any accepted economic theory whatsoever, and it has been solved mainly from an engineering perspective.

In the AESO's *Transmission Loss Factor Methodology Decision Document*, there is no mention of the primary economic criterion for judging a regulatory pricing rule; namely, that it should induce economic efficiency. In this case, economic efficiency just means saving rate payers money with least-cost power production and delivery. In other words, economic efficiency, the central goal of regulatory pricing, was not considered and rejected; it was simply ignored. Out of all the massive calculations concerning loss factors we find no estimate of money saved. PJM (2007a), on the other hand, used such an estimate as its primary justification for switching from average-loss charging (essentially MLF/2) to MLF.

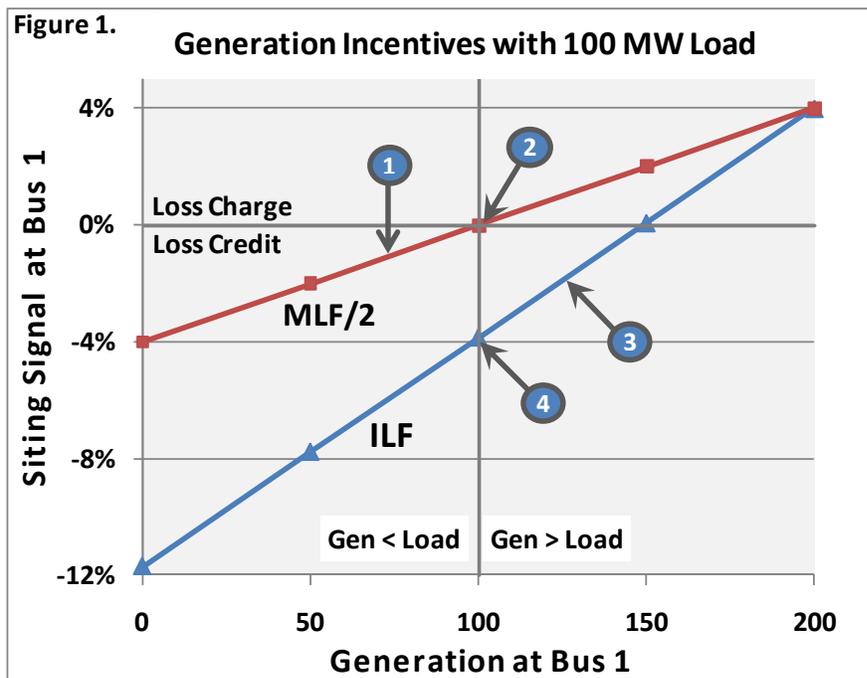
An Engineering Approach to Investors

A second, equally fundamental example of attempting economics with an engineering mindset is the AESO's (AESO, 2005; Teshmont, 2011) use of the loss factors proposed by ATCO and Milner.² The AESO and Teshmont examined whether these incremental loss factors³ would justify the economic siting of new generating facilities in areas which would reduce transmission losses. Economic siting is, in fact, one of the goals specified by the *Transmission Development Policy* (Alberta Energy, 2003), and it is half of economic efficiency. So the AESO is aware, to some extent, of the main economic objective; namely, efficiency, although it left this concept entirely out of its list of 13

²U.S. Department of Energy, *Electricity Delivery and Energy Reliability Report*, 9. This report is analyzed in Appendix 3.

(AESO, 2005).³ But the real trouble comes when the AESO attempts to decipher the price signals.

For example, if we consider Figure 1 below, the AESO and Teshmont see a loss credit at 5
 occurs under their MLF/2 loss-pricing method, so they further conclude their method is sound. But suppose the owner of the generator at bus 1 expanded it by 25 MW to point 2, thereby completely eliminating losses. This would be ideal. But the result would be that the investor would no longer receive a loss credit. In fact, the locational signal here says to lower output
 backwards in this situation. 10



Continuing with Figure 1, the AESO and Teshmont conclude that at point 3 the loss credit
 sends an inappropriate signal to expand, so the AESO says backwards. But if the generator were expanded by 25 MW the credit would vanish, and if it
 reduced its capacity by 25 MW to point 4, its credit would rise from 2% of 125MW (or 2.5
 15 MW), to 4% of 100 MW (or 4 MW). So

³ h The loss factor methodology should provide a long-term generation siting signal principle does not require that the signal should be even somewhat useful.

approach is correctly sending a signal to reduce capacity and output and to decrease losses. (This is explained in detail in Appendix 3.)

5 (assuming that investors think like electrical components inductors and capacitors and not like economic agents. Inductors and capacitors react to their present situation with no thought for the future. However, investors are known to think ahead, and would change to and how would that change my earnings if I built or modified a generator at this bus?

10 Understanding that investors, unlike inductors, consider the consequences of their actions, is not an advanced economic concept and is understood by most non-economists. But it can be forgotten by those who are used to analyzing systems that do not think ahead. This may be why, over at least the last six years, the AESO has failed to understand the meaning of a price signal. The AESO has applied an engineering-based, non-anticipatory approach to model investors and plant operators. Such an approach bears no resemblance to economics, which focuses on the expectations and strategies of economic agents.

15 Misreading the price signals to investors has lead to a focus on superficial loss-factor characteristics that are scrutinized only in Alberta. This has produced a highly complex but largely impotent approach to selecting a loss-pricing method. The method now in use is a hobbled and sloppy form of the average-loss pricing method that has been rejected by the PJM Interconnection, ISO-NE, NYISO, MISO and the California ISO, all of which have adopted
20 full marginal-loss pricing as recommended here as a first step.

The Fundamental Economic Objective

The fundamental economic objectives for the design of transmission loss factors were concisely stated by the Alberta Energy and Utilities Board (the Board), in Decision 2000-27. The Board stated:

25 *The Board considers that, ideally, loss factors to generators should be designed to achieve the following two objectives:*

- Loss signals should provide an appropriate dispatch.*

- *Loss signals should provide information appropriate for generation.*

5 These two objectives are, in fact, the two halves of the economic-efficiency objective that is relevant to loss-factor design. The Board gave a beautifully concise definition of the economic objectives of the regulatory pricing of losses. This is not a matter just of Board policy in 2000; it is a precise summary of the standard economic objectives that govern loss factors. These economic objectives have motivated the rejection of MLF/2 by five of the six electricity markets in the United States (and the sixth does not use MLF/2 either).

10 Unfortunately, nowhere in its (2005) report can there be found a single case in which the AESO accurately tests an example of the efficacy of its 50% Area Loss / system dispatch. And nowhere in its report does it test the ability of its loss factors to induce (signal) an hourly system dispatch. ⁴ In short, there has been no economic analysis of the solution to the economic problem of loss signals, and no economic analysis of the alternatives.

15 *An Economic Approach*

This document takes an economic approach to the analysis of the economic problem of pricing transmission services with losses.

⁴ Although an annual loss factor cannot fine-tune an hourly dispatch, it certainly affects the long-run average dispatch.

3. Pricing Transmission Losses in a Marginal World

Regulating Monopoly Prices

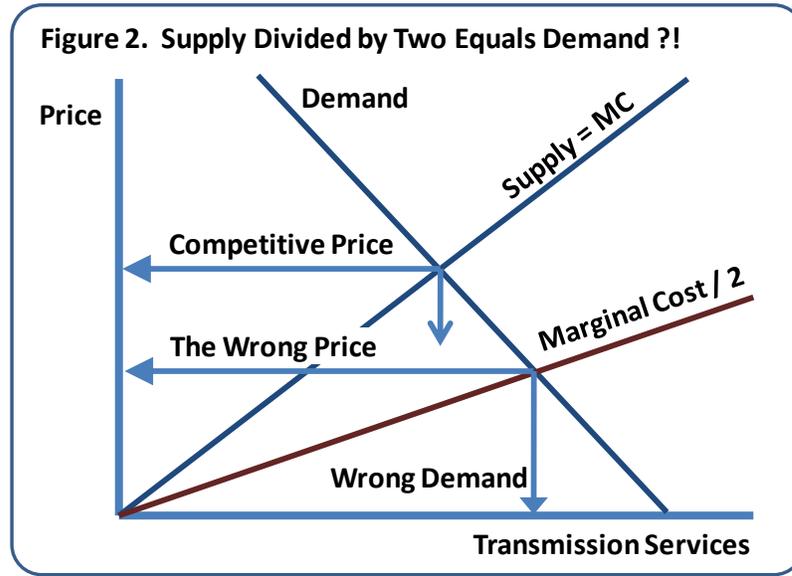
The AESO has a monopoly on transmission services. Consequently, if it were an unregulated private company, with a profit motive, it would price transmission services too high (which presumably is one reason it is a not-for-profit agency). Well-established economic theory predicts overpricing where an entity holds monopolistic power and provides a theory of what prices would be most efficient. As over pricing is predicted, regulation is desirable, and economic theory tells how to regulate such a monopoly price. However, this theory assumes that generators make marginal decisions, and that is occasionally quite far from accurate. Consequently, a modification of standard pricing theory is needed and this modification will be discussed shortly. But it is useful to understand standard economic theory before examining non-marginal situations.

Consider the problem from a high-level economic view. The AESO sells transmission services to generators who use these services to deliver their product to consumers. The price of these services needs to be regulated, and that raises two concerns. First, the price level of transmission services needs to be held in check. Second, relative prices assigned to different generators need to be set correctly. In fact, it will turn out that the problem of setting the general price level is a non-problem as long as any excess revenue collected by the AESO is refunded to load. But if relative prices are wrong, then production and siting will be inefficient. To set relative prices correctly, we draw a lesson from competitive markets, which set their prices efficiently. Economics has found that the competitive *price equals marginal cost*. Since a supply curve is a marginal-cost curve, this is just one aspect of the most basic law of economics, namely that in a competitive market, supply equals demand, and production is efficient.

25 *Marginal-Cost Pricing Is Efficient If Not Divided*

The solution to loss pricing is just that elementary. The best price is the competitive price and that equals the marginal cost of providing the transmission service, which is the marginal cost of losses. The correct loss-pricing rule; namely, price losses at marginal-cost-**not**-divided-by-two, can be found in *Spot Pricing of Electricity*, (Schweppe, Tabors, et al.,

Kluwer Academic, 1989), which has long been considered the bible of electricity pricing (see Appendix 1). For an economist, this completes the basic factors. (factors are one half the marginal cost, and that is simply wrong, as illustrated in Figure 2.



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Figure 2 can be thought of as pertaining to the transmission services provided to a remote generator. Demand is that for transmission services.

Figure 2 shows the standard supply-equals-demand diagram. Just as in the electricity spot market, the supply curve is given by the marginal cost of supply. The competitive price balances supply and demand at the intersection of the two curves. At that point, price equals marginal cost. If the price is set lower by using an artificial and incorrect supply curve, then the demand for transmission services will be too great. In the case of losses pricing in Alberta, the price has been set lower by using the marginal-cost-divided-by-two approach. If we pretend loss costs are half what they really are, generators will not care enough about causing losses.

So where did the anomalous divided by two come from? It is widely understood that marginal-cost pricing (although ideal) usually collects more revenue than the total cost of the input that the marginal cost applies to. So when non-economists see that too much money is being collected, there is a tendency to scale the prices down.

20

Losses follow a simple law quite closely: $Loss = aW^2$, where W is the power flow. Since marginal is an old economics term for derivative, marginal cost means the derivative of cost. In this case, the derivative of aW^2 is $2aW$. Multiplying the marginal cost of power times the amount of power gives $2aW \times W = 2aW^2 = 2 \times Loss$. So charging generators for marginal losses is like charging them for double their actual losses. This strikes non-economist as odd, so there is a tendency to divide the marginal cost by two. Then they are amount of money. But the divide-by-two approach is an accounting approach to pricing and not on an economic approach. It prevents over-collecting (which accomplishes nothing, as is discussed next), but it does not send proper economic signals, which is, or should be, the main goal of pricing losses.

Over-Collecting is Not a Problem

Charging for marginal losses (and using load as the swing bus) will collect more than the cost of the losses; in short, it is not a problem.

1. Change the swing bus.
2. Use a shift factor to reduce all loss factors by the same amount.
3. Divide all loss factors by two and then use a smaller shift factor.

Charging for losses is charging for the delivery of a product to customers. This is not unusual, so we should look at how market order stores pay UPS to deliver their products. So how do businesses handle delivery costs?

Delivery is a cost of doing business, and like every other cost, it is passed through to customers. To stay in business, a business must pass through all of its costs and then some in order to cover a normal return on equity. Businesses do stay in business, so they must be passing through their costs. The same is true for generators.

Now comes the loss charge. Imagine for a moment that no one said it was a loss charge; it was just called a delivery charge. If generators must pay for delivery, are they going to pass on the costs or go out of business? Obviously they will pass them on, just like every business does. But now someone claims the delivery charge is twice too high and should be cut in

half. So the AESO cuts it in half. What will generators do with the new lower delivery charge? They will pass it on. Whatever the cost is, it gets passed on or the generator will go out of business.

5 So was there a problem? And was it fixed? No and No. Passing on a cost to customers is not a problem, and passing on a smaller cost instead is not a fix. Will it help load to have less delivery cost passed through to them? Not at all. If the AESO that load now pays, for example, transmission costs. If the over-collection is given to generators, they will give it to load. Then load will pay less for electricity and more for transmission. (This is further explained in Appendix 6.)

10 charge by half. Fortunately, reducing the delivery charges is easily accomplished. The delivery charge can be cut in half by solutions 2, 3 or 4.

15 Solution 2 (changing the swing bus) and 3 (shifting loss factors) produce exactly the same results, but solution 4 (dividing by two) is different and causes problems. I recommend solution 3 because it is more transparent than solution 2. Solution 3 is compared with solution 4 below, but first an overview may be helpful.

20 As noted, the point of charging for losses is to send price signals, which provide economic incentives. And the point of incentives is to induce generators and investors in generation to reduce the cost of delivered power. Signaling is done by charging the high-loss generators more and giving a credit to the few generators that actually reduce losses. Since the loss charge can be both positive and negative, dividing it by two not only charges the high-loss generators half of the cost they cause, it also gives the loss-reducing generators only half the credit they deserve. Dividing by two cuts the right price signals in half just for the sake of

25 reducing a charge that generators simply pass on anyway. As five of the major US markets have decided, this makes no sense. (Appendix 2 lists their approaches to over collection.)

The Shift Factor versus Divide Two

Economists are familiar with puzzles in which marginal-cost pricing over- or under-collects. They design prices to make markets work efficiently and not waste money.

30 However, these prices sometime do not cover costs and sometimes collect too much. When

prices are too low, economists recommend Ramsey pricing as the way to increase prices to cover costs while keeping price-distortions as small as possible. Ramsey pricing is quite complex. Fortunately, the problem of too-much money is generally simpler than the problem of too-little money. There is a simple way to alleviate the problem of too-much money and still preserve pricing efficiency that is to reduce all pricing, or, in our case, loss factors by the same amount.

This method works because the average price paid by consumers is equal to the marginal cost of production. All that matters are the relative prices between different generators. It is the *distortion of relative prices* that causes the AESO's *By Two* (MLF/2) method to send the wrong signals. This inefficiency can be understood as follows.

Why Dividing by Two Wastes Money

Suppose that Generator **A** can produce power for \$50/MWh but has marginal losses of \$10/MWh and Generator **B** can produce for \$57/MWh but has no losses because it is located in the load center. This scenario is shown in Table 1, below. Suppose that other generators are either cheaper than both of these generators and already dispatched, or more expensive and not needed, but that one of these two generators is needed to serve load. Will the right one be dispatched? In other words, will the cheaper one, counting generation costs and losses, be dispatched?

For simplicity, assume that these are fairly small generators and that Generator **A** is located on a high-capacity line with a large power flow, so that its marginal losses are roughly constant over its output range. Because every MWh generated by **A** causes \$10 of losses, the true cost of power from Generator **A** is \$60/MWh, so Generator **B** is actually the cheaper generator, all costs included.

By two prices signal the market to do? This is a question the AESO forgot to ask because it was taking an accounting-engineering approach rather than an economic approach to pricing losses. After dividing by two, the AESO will charge Generator **A** \$5/MWh (\$10/2) for losses and will charge Generator **B** nothing. This will cause Generator **A** to see its total costs as \$50 + \$5 = \$55/MWh, and if it does not have market power it will bid \$55/MWh. Of course Generator **B** will bid \$57/MWh. The result is that the expensive generator (counting the cost of losses) will under-bid the cheap generator. Consequently, expensive Generator **A** will be dispatched

instead of cheaper Generator **B**. The MLF/2 approach will waste money and consumers will pay more.

Table 1. Why MLF/2 Causes the Expensive Generator to Underbid the Cheap One

	Fuel Cost	Marginal Loss Charge (MLC)	Bid with MLC	Marginal Loss Charge / 2	Bid with MLC/2
Generator A	\$50	\$10	\$60	\$5	\$55
Generator B	\$57	\$0	\$57	\$0	\$57

As shown in Table 1, with full marginal loss charges, Generator **B** wins the auction as it should. But expensive Generator **A** wins the auction when the marginal charges are divided by two. The problem is that dividing by two has altered the gap between the \$10 marginal loss of Generator **A** and the \$0 marginal loss of Generator **B**. That relative gap has been reduced to \$5/MWh from \$10/MWh.

Why Shifting Loss Factors Is Efficient

The divide-by-two rule does solve the problem of too-much money, but it causes the expensive generator to be dispatched instead of the cheap one. In doing so, it solves a need not have been caused. The correct solution is to simply subtract whatever it takes to eliminate the excess revenue. The exact amount depends on the output of all the generators and their loss factors, but let us suppose that subtracting \$3/MWh from all loss charges would get rid of the unwanted revenues. This leads to Table 2.

Table 2. Why Marginal Loss Charges Are Efficient (Save Money)

	Fuel Cost	Marginal Loss Charge (MLC)	Bid with MLC	Marginal Loss #	Bid with U O #
Generator A	\$50	\$10	\$60	\$7	\$57
Generator B	\$57	\$0	\$57	\$3	\$54

With the Marginal Loss Charges shifted down by \$3/MWh, the cheaper Generator **B** still wins by \$3/MWh, just as if price was set to full marginal cost. So the economic recommendation is to compute the marginal loss charges per generator, find the over collection for the system, divide that by the total power delivered, and *subtract* the resulting *shift factor* from the marginal loss charges.

Now, I have said that the correct price is the full marginal cost and neither shifting down nor dividing by two will leave price equal to full marginal cost. So exactly why is one price distortion better than the other? Both approaches (shifting down and dividing by two) take away the same amount of revenue from generators, so there are just two problems to worry about: (1) generators might pass on the lower average price to consumers, who might buy too much electricity; and (2) the transmission cost (losses cost) differential between generators might distort the dispatch. Both approaches would cause problem #1 to the same extent, but dividing by two causes problem #2, while shifting does not. This gives shifting the advantage.

10 But the difference is more stark. A closer look shows that problem #1 is not really a problem at all – it is not a problem for either approach. First, consumers will respond very little to the relatively small cost of losses. But more importantly, they will not see any price reduction at all from either approach, so the first problem simply does not exist. Why is this?

15 One of two things will happen. Either the AESO will over-collect and pass the revenue on to load. Or the AESO will not over-collect and the generators will pass the revenue on to load. In either case the effective prices received by generators will be the same, so the dispatch and locational signals will be efficient. (An example of this is shown at the end of Appendix 6.)

20 If the AESO over collects, that, in effect lowers the price generators get, but then they bid the price up. If the AESO does not over-collect, the generators bid the price down and pass the benefits on to load. Hence, only the second problem (distorted relative transmission prices) is real, and shifting loss factors avoids this problem while dividing by two causes it.

Long-Run Dispatch Signals also Provide Locational Signals

25 “... provide an appropriate economic signal for the siting of new generation? It is important to notice that the Board was thinking in terms of price *signals* (economics) and not in terms of price accounting. Fortunately, the two concerns (dispatch and locational investment signals) are parallel. The incentive to build generation comes from the price of power – not from the hourly price fluctuations, but from the long-run average price. Using a shift factor restores the proper

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long-run average price advantage for Generator **B**, the generator with no losses, because Generator **A** is charged (relative to **B**) for the full marginal-loss differential. This long-run advantage of lower loss charges is exactly the right signal for investing. (This is discussed further in Appendix 8)

- 5 This concludes the high level view of basic loss charging in a world with marginal decision making. The simple answer is to set the price of transmission services equal to the marginal cost of transmission services. This is simply Economics 101. However, if the extra revenue collection is considered to be a problem, these revenues can be returned to generators by shifting all loss factors down by a constant amount. This will not distort the relative,
- 10 locational loss-pricing signals. *In no case should marginal cost be divided by two.*

believe that investors did not anticipate their own investment, but simply assumed the loss factor would remain unchanged.⁵

5 So what loss factor will the investor actually get? Once the 50 MW generator is built, it will supply all of local load, so there will be no power flow on the line from the system, and there will be no losses, so the marginal-loss factor will be zero. The last step is crucial but not as obvious as it sounds as the box just below explains.

When loss is zero, marginal loss is zero!

10 It may sound natural that marginal losses are zero when losses are zero, but it is quite surprising. Before you purchase your first drop of gasoline, the marginal cost per litre of gasoline is \$4.00. After you purchase your first drop, the marginal cost is still \$4.00 per litre. The cost of transmission is not like that.

15 If the first megawatt of transmission causes 4 kW of loss, then two megawatts of transmission use causes 16 kW of loss. And going the other way, half a megawatt of transmission causes only 1 kW of losses. The total cost of transmission goes up quadratically (as the square of use) not linearly like the total cost of gasoline. Since the square of one is one, but the square of 1/10 is 1/100, the marginal cost vanishes as the amount of transmission used goes to zero.

20 With an incremental investment decision and marginal loss factors, the investor gets no loss credit whatsoever (in the present example) when he builds a generator. This is because building a 50 MW generator will eliminate the use of the transmission line, sending losses and marginal losses to zero. With zero marginal losses, both MLF and MLF/2 are zero. Consequently, there will be no investment signal even though there should be an enormously strong signal to build the 50 MW generator. Consequently, the investor cannot afford to invest if a remote 50 MW generator costs even \$1/MWh more to operate than
25 buying power from the system. So even though the generator would save \$500/hour in losses, and generation would cost only an extra \$50/hour, the investor will not invest. For this incremental decision, marginal loss factors (MLF or MLF/2) are completely worthless.

⁵ See Appendices 3 and 9 for details.

The Effect of Using Incremental Loss Factors

Incremental losses (IL) are simply losses with the generator minus losses without the generator. That is a bit less mysterious than the MLF. And when the decision is between having the generator and not having the generator, this is exactly the right approach. In the present example, the ILF is found as follows:

$$IL = (\text{Losses with the generator}) - (\text{Losses without the generator})^6$$

$$IL = (0 \text{ MW}) - (10 \text{ MW}) = -10 \text{ MW}.$$

$$ILF = IL / (\text{power delivered}) = -10 \text{ MW} / 50 \text{ MW} = \text{a } 20\% \text{ loss credit.}^7$$

Since a 50 MW generator reduces the losses by 10 MW, it gets a 10 MW loss credit, so it will be paid for the losses it prevents. Since system power costs \$50/MWh, this means the loss credit will be \$500/hour.

Although this seems completely reasonable, economics demands more. Economics requires that a policy actually work. In other words, it must signal market participants to behave efficiently and minimize the cost of producing power. This is what was left out of the AESO analysis. There was no check on whether or not policies worked. There was simply a list of what someone considered to be nice properties, and policies were evaluated against these properties. This is not economics, and it is not a reasonable way to design system policies. So we must ask, how will an ILF policy affect investment decisions, and will it work?

Fortunately, the answer is straightforward. The investor is paid the full Value of the Losses Eliminated (\$VLE/hour). Suppose the 50 MW generator costs an extra \$X/hour compared to system power. The investor's profit will be \$(VLE - X)/hour, because ILF pays the generator the full value of the losses it eliminates. Of course, investors maximize profits, so the investor will maximize (VLE - X). Is that best for the system?

⁶ Another approach calculates the ILF directly as the average of the MLF when the plant is on and when it is off (first and last MW). This gives the same answer as the approach explained here because losses are quadratic. But the formula given here is a more general definition and often provides more insight. However both approaches are useful, and they are compared in Appendix 1.

⁷ Loss factor can be defined by dividing losses by either the power injected or by the power delivered to the swing bus. As shown in Appendix 7, dividing by power delivered makes shifting loss factors efficiently very convenient.

The system should minimize the net cost of providing power. But \$VLE is a savings, so more of that is better, but \$X is a cost. So the system also wants to maximize (VLE - X).

Clearly, investors will maximize exactly what the system needs maximized in order to minimize the total cost of production and losses. Investors do this, not because they care, but because their profit equals the net savings to the system. In econ-speak their incentives have been aligned with social welfare.⁸

And notice that this simple argument did not depend on whether the investment decisions were marginal or incremental. Using ILFs aligns incentives and minimizes system costs in either case. This argument also holds when a generator is causing losses and VLE is negative. In this case the investor will not invest unless his excess cost of generation (relative to the system) is negative. Also notice that with an incremental decision, the ILF policy works perfectly even though MLF fails completely.

Why MLFs Can Stumble Even with Marginal Decisions

We have seen that ILF works perfectly with both marginal and incremental decisions, and that MLF fails with incremental decisions. One might hope that MLF would always succeed with marginal decisions. But this is not always the case. MLF needs two special circumstances: (1) highly competitive investors, and (2) highly marginal decisions.

The problem for MLF is market power – the ability of an investor to influence the price of transmission, or, in other words, in our case, the loss charge. For MLF to send perfect signals, the investor must view the MLF (the price of transmission) as beyond its control. Otherwise the investor will be motivated to manipulate the MLF to achieve greater profit, and this will interfere with its intended price signal.⁹

We have already seen that MLF fails when decisions are incremental. We now consider the two polar cases for marginal decisions, (1) when the investor has no competition, and (2) when the investor has perfect (extreme) competition. Assuming highly marginal decisions means that investors can build any size plant and that, no matter what size, it will produce

⁸ Although consumers gain nothing, they also lose nothing in this initial situation. But if there is future load growth and another generator enters, it can be shown that consumers will gain as ILFs approach MLFs. This convergence in large systems is discussed in Appendix 1.

⁹ In ec

power (in this example) for \$4/MWh more than the cost of power (\$50/MWh) from system generation. The investor then considers building every size plant, from the smallest on up to find which would be most profitable. Remember that marginal losses are 40 percent (a credit of \$20/MWh) for a 0 MW investment and that credits fall to zero for a 50 MW generator. At 40 megawatts, loss credits are down to \$4/MWh, and this just balances the extra cost of remote generation.

This much just describes the assumption of highly marginal decisions. Now we come to the fork in the road, with one path explaining what happens with perfect competition and the other explaining what happens with market power.

Market power is perhaps easier to explain. When the investor considers a 39 MW power plant, he sees a marginal loss credit of \$4.40, which is more than his \$4.00 extra cost of generation compared to the pool price. So the next step looks profitable. But if he takes it, the MLF falls to \$4.00 and he just breaks even on all 40 MW. If he stops at 39 he earns a \$0.40 profit « a little better. But why not back up to 38 MW and earn an \$0.80 profit on 38 MW. Even better. Continuing that logic, he arrives at a most profitable investment size of just 20 MW. (This can be seen in Figure 4 at the point where the vertical red line marks maximum profit under MLF.) This is not efficient. The 40 MW generator would save an extra \$160/hour of losses at an extra cost of only $\$4/\text{MWh} \times 20\text{MW} = \$80/\text{hour}$.

Competition, on the other hand, drives the investor to build all the way to 40 MW. Here is why. Suppose the investor has gotten as far as considering a 39 MW plant with a loss credit of \$4.40/MWh. Without a competitor, we found just above that he would turn around and find more profit with smaller investments. But with a competitor, he realizes that if he drops back to 38 MW his competitor will build a 1 MW plant to earn a \$4.40 credit and make \$0.40 profit over and above the extra \$4.00 cost of generation. And once the competitor does that, there will be 39 MW in the market (38 + 1) and the marginal loss credit will be \$4.40 and not the \$4.80 the investor was hoping for. So competition prevents him from manipulating the price of transmission the loss charge and the investor finds it more profitable to build the full 39 MW himself.

If we told the competition story with finer increments, 0.1 MW instead of 1 MW increments, competition would push the investors past 39 MW to 39.9 MW. Of course the idea that tiny

generators can produce power at the same price per MWh as larger ones is unrealistic. Investment decisions really are incremental. But this demonstrates the meaning of the assumptions that underpin the optimality of MLF.

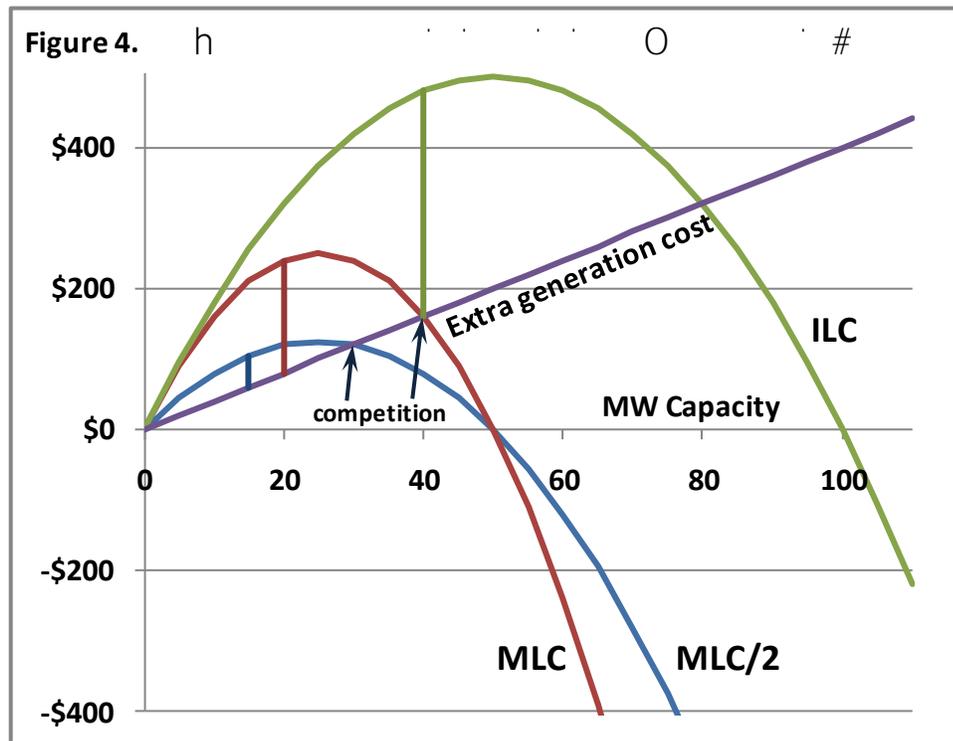
Diagramming Investment Decisions under ILF and MLF

5 The basic points concerning locational investment signals from ILF and MLF transmission pricing methods have been reviewed. However, a little more insight can be gained from a graphical analysis that shows the loss credit and cost curves that determine profits. Price signals work only by affecting profits.

Figure 4 shows the loss credits (credits because these investments reduce losses) that would be paid by the three different policies (MLF/2, MLF and ILF) and it also shows extra generation costs (above the pool price) that are common under the three policies. The three credit curves assume a single investor with no competition.

The values of the marginal loss credit divided by two (MLC/2), the marginal loss credit (MLC), and the incremental loss credit (ILC) curves are just the dollar credits computed from the loss factors and the generation outputs. The three curves show the loss credits an investor would get, depending on what size generator was built and operated. Since the ILC gives full credit for reducing losses, that credit is maximized by building a 50 MW generator, which exactly supplies the load, and eliminates all transmission and losses. The investor would like this maximum credit, but this would require producing 50 MW of power, and the investor loses \$4/MWh on all power produced. So as loss credits level off, producing more power gains less in loss credits than is lost to extra production costs. So instead of maximizing his ILC and ignoring extra production costs, the investor looks for the size generator that maximizes his profit; that is, the amount by which his loss credit exceeds his extra generation costs. The vertical (green) line at 40 MW marks the profit-maximizing size of generator, and that is the size that will be built.

The other two loss policies, MLF and MLF/2, pay less and peak at lower capacity levels. So when the investor applies the same profit maximization rule under these policies, he decides to build smaller generators than under ILF. The profit maximizing investments are marked by vertical lines, the heights of which represent the investor profit, which is the loss credit minus the extra cost of remote generation.



In Figure 4, an investor can build any size generator and produce power for \$4/MWh generation. The Extra-Credit curves and the Extra-cost line is the investor's profit. The three profit maximizing investments are shown by the three (green, red and blue) vertical lines. The MLC curves assume the investor has no competition from other investors.

5

Although Figure 4 illustrates profit maximization when investors under MLC/2 and MLC have no competition, the competitive outcomes are also easy to spot on the graphs. For these two policies, competition will push profits to zero (which still leaves a normal return on equity). These two points are marked by arrows in Figure 4. Since under ILF, an investor does not withhold capacity, and builds the optimal amount, competition will not change the outcome. (In other words, ILF solves market-power problems and leads to greater efficiency.)

15

To summarize, without competition from tiny power plants, MLC/2 and MLC policies will cause under-investment. With perfect competition MLC can reach the optimal investment level, but MLC/2 cannot. But if decisions are incremental MLC/2 and MLC will fail

completely in the present example. These results are summarized in more detail in Table 3 below.

Table 3. Marginal versus Incremental Loss Factors

Loss Policy:	MLF/2	MLF	ILF	Optimal
Investment Decision Type	Capacity of Generator in MW			
Marginal with Competition	30	40	40	40
Marginal with Single Investor	15	20	40	40
Incremental: 0 or 50 MW	0	0	50	50

Optimal means the investment that minimizes the sum of generation and transmission-loss costs, given the available generation options. All generators are assumed to produce at \$54/MWh, while the system marginal cost is assumed to be \$50/MWh.

Note that incremental loss factors perform optimally in all three circumstances. In a world with marginal investment choices, full marginal loss factors will induce somewhere
 5 between half-optimal and optimal investment depending on how much competition there is. (μ_j ' ° | ' # - ' œ MLF/2; can° perform only moderately well under idealized assumptions about extreme competition from tiny generators. But inspection of Figure 4 shows that MLF/2 is likely to fail completely, because even at its most profitable point a
 10 15 MW generator it is barely profitable. So any slight increase in the extra cost of production at this low capacity size would make every size generator unprofitable, and MLF/2 would induce no investment at all. In other words, the investment decision only needs to be slightly incremental before MLF/2 fails completely.

Table 4. shows the *net* benefits of the various policies under the various circumstances. Viewed from the perspective of net benefits, which is the one that matters, MLF/2 and MLF
 15 perform somewhat better, but they are still just as likely to fail completely when the investment decision is too incremental in nature.

Table 4. Net Benefit Under Marginal & Incremental Policies

Loss Policy:	MLF/2	MLF	ILF	Optimal
Investment Decision Type	Net Benefit in \$/h			
Marginal with Competition	300	320	320	320
Marginal with Single Investor	195	240	320	320
Incremental: 0 or 50 MW	0	0	300	300

The Net Benefits are the reductions in losses minus the extra cost of remote generation.

Dispatch Decisions under ILF and MLF

The discussion above concerns investment decisions, but dispatch decisions are driven by the same loss factors, and they have essentially the same properties in both cases. The ILF still rewards generators for the effect on losses of their entire output. So it sends the correct marginal signal for a small increase in output, and it sends the correct total signal for the total output. Similarly MLF sends a correct marginal signal, but if a generator is large enough to affect its own MLF (if it has market power) then the signal will be distorted by that market power. And if the generator must make an incremental decision to shut down or keep running then MLF will send the wrong signal. And, of course, as always, dividing by two makes all the signals half as big as they should be for all the cases in which the MLF is designed to work correctly.

5. Conclusions

Competitive markets equate price and marginal cost, and this makes them efficient. If transmission and generation could be provided in small increments by independent suppliers, a competitive market would set loss charges according to MLF and not MLF/2.

- 5 Generation might feel over charged, but the system would operate efficiently, and generators would not be harmed.

Since networks do not lend themselves to competition, they need to be provided by a monopolist and the price the monopolist charges needs to be regulated. Economics recommends setting the price according to MLF (price equal to marginal cost) in order to
10 achieve efficiency. This would work perfectly if generation owners made decisions in very small increments. But generation investors make decisions that are relatively discrete, and even plant operators are limited in the output levels that make economic sense. So generation decisions cannot always be considered marginal in the stringent sense required by economic theory to justify using MLF.

- 15 In particular, generators on relatively small lines find themselves making decisions that affect their own marginal loss factors. This is a sure sign that the assumptions of perfect competition have not been fulfilled, and that MLF will not give optimal results. In such situations incremental loss factors can do much better. Fortunately, in the cases where MLF works well, ILF works equally well. In fact when MLF works perfectly ILF equals MLF.
20 Moreover, there are many situations where MLF fails but ILF sends exactly the signals MLF was designed to send but fails to send under non-marginal circumstances.

Consequently, the first and most obvious step for the Commission is to ask the AESO to stop cutting the standard marginal prices in half. And, the second step is to ask it to implement an ILF methodology so that investors facing non-marginal decisions will receive more
25 appropriate loss signals and make more efficient choices. Both steps will result in power being produced and delivered more cheaply, to the benefit of Alberta as a whole.

APPENDICES

1. *Comparing MLF/2, MLF and ILF*
 2. *Precedents and Standard Procedures*
 3. *Can the AESO and Teshmont Get Generators Out of Stray?*
 4. *Why Not to Divide by Two: An Example*
 5. *Harming the Benefactors; Helping those Who Cause Losses*
 6. *Why Over-Collection Is Not a Problem*
 7. *The Theory of Shifting Marginal Loss Factors*
 8. *Do Existing Plants Need Locational Signals?*
 9. *How Not to Analyze Price Signals*
- References*

1. Comparing MLF/2, MLF, and ILF

This report has discussed three loss-pricing methods: the current one (MLF/2), the generally accepted standard, which assumes marginal decision making in an idealized world (MLF), and a more innovative one that assumes incremental decision making (ILF).

5 Comparisons have been made in specific cases, but it may be helpful to step back and gain a broader view of all three.

Two approaches to this comparison are needed; the bottom-line approach and the incentive approach. Existing generators are interested in the bottom line; how much will they be charged or credited? But the Commission should be concerned with incentives – the price signals that make the market work well or poorly. The bottom-line approach is simplest, but as Appendix 3 explains, the AESO and Teshmont have for a number of years confused the bottom-line with price signals, so caution should be exercised when reading this section. *Payments are not incentives* Incentives are the result of how payments *change* when some target behavior changes, and that can be a world apart from simple bottom-line

15 charges and payments.

Table 5. Comparing the Bottom Lines

Case	Marginal Loss		Raw Loss Factors			Value to Generator
	First MW	Last MW	MLF/2	MLF	ILF	Low/Neg. ç è High
1	More Negative	Negative	credit	More credit	Most credit	MLF/2 < MLF < ILF
2	Negative	Zero	0	0	credit	MLF/2 = MLF < ILF
3	Negative	Same as 1 st , but positive	charge	Greater charge	0	MLF < MLF/2 < ILF
4	Zero	Positive	charge	Greater charge	Same as MLF/2	MLF < MLF/2 = ILF
5	Positive	More Positive	charge	Greatest charge	Greater charge	MLF < ILF < MLF/2
6	Positive	A tiny bit more Positive	charge	Greater charge	Greater charge	MLF = ILF < MLF/2

* Š ¨ ± j ¨ ° « ¨ fi j ¨ a j ® Š ¨ « ® ¨ ¥ ¨ ¨ ¨ a j £ Š ¨ ¥ ¨ 2 j ¨ This is based « ® only on the raw loss factors.

Case 5 deserves special attention because, if there is a typical case, this is it. On average, generators are transmitting power over a line with losses and their output adds to the losses. In this case (case 5) high-loss generators because it slices their raw loss charge in half. ILF does not do that, but compared with MLF, it gives them a break. For large generators, this can be a significant break, but for smaller generators on a line with a large power flow, ILF and MLF are nearly identical.

The Identity of ILF and MLF Under Marginal Conditions

ILF is designed to fix a problem with MLF, the standard approach. But MLF has been proven ideal under competitive, working when fixing something else. So ILF should not break MLF when MLF is working perfectly, and it does not. ILF price-signals align perfectly with MLF under the marginal assumptions that make MLF perfect.

As noted above it is important to check both the bottom line and incentives. First, we check the bottom line.

The Bottom-Line Comparison (for generators)

In competitive markets, are too small to change it (they do not have any market power). This is the key assumption of competitive market theory, and it is the basis of marginal analysis. If a marginal player turns its generator on or off, the loss factor will not change. Of course that would mean the player is infinitely small, which is impossible. But this is the assumption under which MLF has been shown to work perfectly. (In reality it just works very well most of the time.)

So we need to check the bottom lines for ILF and MLF under the competitive assumption that individual generators cannot affect the price of losses. That means the marginal loss does not change when they turn on or off, and that means the marginal loss of the first megawatt-in equals the marginal loss of the last megawatt-in. But if the first and last are the same then, when ILF takes the average of the first and last marginal losses, it just gets the constant marginal loss that applies to every MW the generator produces. So ILF equals the marginal loss of the last megawatt-in, and so it equals MLF. They are identical.

from two perspectives, so we will use the other formula for ILF. There are two formulas and

they give the same answers. Let ML mean the marginal loss, the fraction of power lost when a tiny bit of extra power is transmitted from the generator to the swing bus.

$$\text{ILF Loss Charge} = \text{Output} \times [(\text{ML of First MW}) + (\text{ML of Last MW})] / 2 \quad (\text{F1})$$

$$\text{ILF Loss Charge} = (\text{System losses with all MW in}) - (\text{System losses with no MW in}) \quad (\text{F2})$$

5 $\text{MLF Loss Charge} = \text{Output} \times (\text{ML of Last MW}) \quad (\text{F3})$

We just made use of formulas F1 and F3 to argue that ILF and MLF were the same when the generator was so small that $(\text{ML of First MW}) = (\text{ML of Last MW})$. Now we will do an example with formula F2. Suppose a 50-MW generator is participating in a 2-GW power flow from North to South. Suppose line losses on the north-south corridor are 5 percent on a 2-GW flow, or 100 MW. Marginal losses would be 10 percent, so the Raw MLF of the 50-MW generator would be 10%. What would the Raw ILF be?

Losses are proportional to the square of the power flow. Without the generator, losses would be only $1.95^2/2^2$ as big. In other words, they would be 95.06 MW without the generator instead of 100 MW of loss with the 50-MW generator. So by formula F2, the ILF is $100 - 95.06 = 4.96$ MW out 50 MW, which is an ILF of 9.88%. This is extremely close to the MLF of 10%, and the small difference is simply due to the fact the small generator is not infinitely small.

The Price-Signal Comparison

Incentives are what matter for efficient markets, and price signals provide these incentives. For a small generator on a large line, we just saw that ILF and MLF are essentially the same. So consider a small generator trying to decide whether to locate on a certain high-loss line or a different low-loss line. It will get the same raw loss factor under ILF as under MLF in either location. The difference between those loss factors will be the same under ILF as under MLF. And, as long as μ is the same, shifting all factors the same amount, and not by dividing by two, this difference, and hence the locational signal, will remain the same for the final loss factors under either ILF or MLF.

Now let us examine a more surprising case. In this case, ILF sends the signals that MLF is designed to send but that it fails to send because the generator is non-marginal. In other words, ILF can send a true marginal signal even when the MLF signal gets distorted by non-marginal generators with market power.

Consider a generator on a line by itself (just for simplicity). With zero output, there are no losses, and with 100 MW of output, losses are 10 MW. What is the loss-price incentive for the generator to produce one more megawatt? The desirable answer according to competitive theory is a charge equal to the marginal loss. Since the next megawatt will increase losses by 0.2 MW, if the price of power is \$50/MW, there should be a \$10/MW *disincentive* to produced more power. So if the generator can produce the next megawatt for \$35/MW, it should be produced. This is the marginal analysis and it gives the correct answer the answer that would lead to efficient production.

Which loss-pricing method will send this efficient marginal price signal? Total losses are $W^2/1000$, where W is the power produced. So the marginal loss factor is $W/500$. Hence at 100 MW the MLF is $100/500 = 20\%$, while at 101 MW the $MLF = 101/500 = 20.2\%$. Using this formula we can find the loss signal by comparing the loss *charge* with and without the extra MW.

Loss charge = $MLF \times (MW \text{ produced}) \times (\text{price of power})$

Loss charge at 100 MW = $20.0\% \times 100MW \times \$50/MWh = \$1000/h.$

Loss charge at 101 MW = $20.2\% \times 100MW \times \$50/MWh = \$1020/h.$

So the generator must pay \$20 more in loss charges if it produces one more MWh. But this is double the price signal which we just found

The reason MLF does not provide the proper marginal signal is that this is not a marginal (small) generator relative to the flow on the line. So the generator is not the

And, producing one more MW does increase the price of losses, and that price increase affects the whole 100 MW of production. This adds an extra \$10/hour to its loss charges, doubling the disincentive and making it twice as high as the correct marginal incentive.

Now consider a generator under ILF, and apply formula F2 above

Loss charge at 100 MW = $(10.0 MW - 0 MW) \times \$50/MWh = \$500/h.$

Loss charge at 101 MW = $(10.2 MW - 0 MW) \times \$50/MWh = \$510/h.$

So the generator must pay \$10 more in loss charges if it produces one more MWh. And this is exactly the \$10/MWh disincentive to produce more that marginal economic theory tells us is optimal. ILF charges for actual losses, so when one more megawatt causes a marginal loss of 0.2 MW, it tacks on that marginal loss and charges for it. And it does not increase the charge on all the previous megawatts as does MLF.

So not only does ILF not break MLF in the cases were MLF works perfectly, ILF actually extends the range of situations in which the price signal is the efficient marginal cost signal. It extends this range into non-marginal territory where generators are large enough to affect the marginal loss factor.

10 *When ILF differs from MLF and MLF/2*

As just seen, MLF fails to send the marginal signals it is designed to send when it gets into certain non-marginal situations. But the situation we considered was a marginal change by a non-marginal (sizable) generator. In that situation, which was Case 2 in Table 5 (no losses with the generator off), it just happens that MLF/2 gives the right answer. However, once the generator becomes a little more marginal in other words, when it is supplying less than 100 percent of the power-flow on the line, MLF/2 is also wrong, but ILF is still right. (This can be easily checked numerically.)

But the situation we want to consider next is tougher. In the above situation, the decision to produce one more megawatt or not was marginal. But what happens if the decision itself is non-marginal? Then we have a non-marginal decision in a non-marginal context. This is the case when an investor considers whether to build a generator or not and the generator is on a fairly small line. It is also the case when a plant operator must decide to take the plant off line or keep it producing, and the generator is sizable compared with the flow on the line it connects to. These are non-marginal decisions and they create more serious problems cases where the efficient price signal lies far from the range governed by MLF/2 and MLF.

Section 4 of this report discusses such a case. In that example a new 50-MW generator was much needed and would reduce losses to zero. As a consequence it would receive no payment from either an MLF/2 or an MLF approach. However ILF would pay it for exactly

its loss reduction. So in these strongly non-marginal cases, where MLF/2 and MLF fail miserably, ILF comes through with the correct signal.

Why ILF Is Not Quite As Easy As It Seems

5 calculated perfectly. It can however be calculated perfectly whenever MLF works perfectly, work and in these cases there is no perfect method for calculating ILF.

10 So calculating ILF will require the choice of a swing bus for the first and last MW produced. Choosing the distributed load-weighted swing bus that the AESO now uses should work well enough. But it is possible that a better choice is available, and surprisingly, this may be, or may be closer to, the distributed generation-weighted swing bus.

15 Two other issues deserve mention. First, generators may dislike having a nearby competitor with a different loss factor. Consequently, it may be worth considering using a fixed-size increment, for example 50 or 100 MW. This would be a compromise. Also this might prevent a subtle, but unwanted incentive to build larger generators, and it would eliminate possible disputes over exactly what constitutes one increment of generation.

20 What this report makes clear is that MLF/2 is simply a mistake, MLF is perfect under the most ideal circumstances, but ILF gives the same price incentives in all of these ideal situations and gives the answer MLF should have gotten in many less ideal circumstances. Moreover, IFL continues to score perfectly in completely non-marginal situations where MLF fails completely. Although the choice of swing bus leaves ILF slightly ambiguous, any reasonable choice (such as the distributed load-weighted swing bus that the AESO now uses) should provide a significant improvement over MLF, which is already far better than MLF/2.

2. Precedents and Standard Procedures

5 The choice between MLF/2 and MLF is not peculiar to Alberta. Because over collection is viewed by generators as a problem, there have been proposals for MLF/2 from the beginning. Some systems adopted this approach and others did not, but those that initially adopted MLF/2 have now seen the error of their ways.¹⁰

10 (Sometimes ILF is termed an average marginal loss rate. MLF/2 is also called a system wide average loss rate, because total loss charges cover total system losses, so losses are paid for on average. This is a system wide average and is completely unrelated to the ILF average. When PJM says it was charging losses based on

The California ISO

In *Power System Economics* (Stoft, 2002), I stated:

15 *As an example of such inefficiency, consider the California ISO which computes the "full marginal loss rate" for each location. It does not charge generators this rate. Instead, it scales it down by the "loss scale factor" to find the "scaled" rate. This mechanism for the Average Loss Rate was invented to pay lip-service to economics while pursuing a regulatory approach.*

20 Although I doubt my statement precipitated the change, the CAISO tariff now takes a different approach than it did when FERC first approved its tariff. The current *CAISO Business Practice Manual for Market Operations* (Last Revised: January 26, 2011) states on page 51:

25 *The CAISO Energy Settlement process includes settlement of the marginal cost of losses through the Marginal Cost Component of the LMP. Because Marginal Losses are higher than actual losses (almost by a factor of 2), the LMP settlement results in*

¹⁰ The ERCOT system in the State of Texas has adopted an approach peculiar to Texas.

¹¹ California uses load as the reference bus (explained in the next chapter) to calculate nodal marginal losses. Although nodal marginal losses from generators are not necessarily double average losses, they are nearly so (on a per-unit basis) throughout the ISO Controlled Grid.

loss over collection. CAISO gl its Neutrality ut es the Adjustments in CAISO Tariff Section 11.14.

Losses in PJM

“ i £ ¥ a a ¥ a £ ‘ « a ‘ † ± a i [Locational Marginal] pricing approach \$ will be
5 modified to calculate transmission loss costs on a marginal basis, or Marginal Losses. The
new LMP calculation will now calculate the full marginal cost of serving an increment of
“ « š Ÿ ‘ š ° ‘ j š œ ± ‘ > Before switching to marginal-loss charging, PJM issued a list
of Frequently Asked Questions (PJM, 2007a). It begins > μ ‘ a « ° ¥ a £ ‘ ° œ ISOs - j 2 j ® š
± š 2 j ‘ š ‘ ® j š Ÿ μ ‘ ¥ © - ‘ ‘ © j a ° j Ÿ ‘ ! š ® £ ¥ a š ‘ ‘ ž « - - j - ‘ ¥ a ° « ‘
10 œ « © - š ® j ‘ ‘ ° ± j ‘ \$ † ! ‘ ¥ © - ‘ ‘ © j a ° š ° ¥ « a ‘ 3 ¥ NE, and NYISO j ‘ © š | « ®
© š ® £ ¥ a š ‘ ‘ ‘ « - - ‘ For instance, since all of these over-collect losses, the four
different methods of refunding the over collections are compared.

- < **PJM:** Allocated to Transmission Users based on load plus exports ratio share.
- < **MISO:** Load Ratio Share within loss pools. Allocation to loss pools determined
15 š œ œ « ® Ÿ ¥ a £ ‘ œ œ š ® £ j ‘ ‘ ¥ a œ ± ® ® j Ÿ ‘ ¢ ® « © ‘ £ j a j ® š ° ¥ « a
- < **NYISO:** Over collection Reduces amount of Minimum Generation and Startup
Residual Uplift allocated through Schedule 1. Essentially reduces load ratio share
charges.
- < **ISO-NE:** Allocated according to Real-Time Adjusted Load Obligation.

20 The point is that collecting a bit too much money is generally not found to be a problem.
Over-collections resulting from efficient charges, such as marginal losses, can always be
used fill revenue gaps that would otherwise be covered by inefficient charges. (This is a
general principle of taxation – efficient taxes should be prized because most taxes cause a
significant amount of inefficiency. Thirty percent is a commonly cited estimate.)

25 The FAQ also includes some other interesting observations, such as fact that PJM will
change references buses and completely recalculation losses for all load and generation
nodes every 5 minutes.

*PJM will use a distributed load reference in the calculation of Marginal Losses.
Because the demand at each load bus can change with every execution, the*

distributed load reference is recalculated each and every execution. For the Real-time LMP calculation, this occurs every 5 minutes and will use the actual load MWs at each load bus for the given period the calculation is executing.

The Spot Pricing Bible

5 As mentioned above, *Spot Pricing of Electricity* (Schweppe, Caramanis, Tabors, and Bohn, 1987) is, to this day, considered the bible of electricity pricing. So it may be worth reproducing Section 2.2. Components of Hourly Spot Pricing. It must be noted that in this treatise, and in all five markets just discussed, competitive prices are allowed, so every node gets its own price. Fortunately, for losses (though not for congestion), Alberta's regulations
 10 have provided a way to implement locational prices by using locational transmission charges. So $p_k(t)$, the spot price at bus k at time t in Schweppe, should be interpreted for Alberta as $p(t)$, the uniform spot price, times $(1 - F_k)$, where F_k is the loss factor, at bus k . Here, then, are the components of the competitive spot price:

SECTION 2.2. COMPONENTS OF HOURLY SPOT PRICES

The hourly spot price associated with the k th customer during hour t is viewed as the sum of individual components defined by^{3,4}

$$\begin{aligned}
 \rho_k(t) = & \gamma_F(t) && \text{[Generation Marginal Fuel]} \\
 & + \gamma_M(t) && \text{[Generation Marginal Maintenance]} \\
 & + \gamma_{QS}(t) && \text{[Generation Quality of Supply]} \\
 & + \gamma_R(t) && \text{[Generation Revenue Reconciliation]} \\
 & + \eta_{L,k}(t) && \text{[Network Marginal Losses]} \\
 & + \eta_{QS,k}(t) && \text{[Network Quality of Supply]} \\
 & + \eta_{R,k}(t) && \text{[Network Revenue Reconciliation]} && (2.2.1)
 \end{aligned}$$

Quality of supply components arise when generation or network capacity limits are being approached. Thus they serve as curtailment premiums or reliability surcharges. The components of (2.2.1) are often combined into groups such as

15

3. Can the AESO and Teshmont Get Generators to Stay Put?

As explained in Section 2 of this evidence, designing loss factors to send locational signals to investors is an economics problem. Investors respond to money, not voltage. In spite of this, the AESO has repeatedly retained Teshmont to study and design its loss factors. Teshmont notes that it is a world leader in high voltage power transmission engineering. However, (j - x © « a ° s shows no expertise in economics, and, indeed, Teshmont makes no claim to any expertise in economics.

In its most recent report (Teshmont, 2011), Teshmont makes use of few if any economic concepts and employs only « a j i j œ « a « © ¥ œ ° j ® © ° - ¥ £ To be effective, signals need to be conditional on performance. Most parents understand this concept. Almost all parents have at some point made an allowance or payment conditional « a ° x j ¥ ® ° œ x ¥ ° Ÿ ° - ° > j x š 2 ¥ « ® ° - š µ ° j š ® a ¥ a £ ° £ « « Ÿ ° £ problem is that Teshmont overlooked the conditional aspect of the signal. Sometimes there is a loss credit, and Teshmont concludes that ¥ ° - ° š ° - ¥ £ a š ° ° « ° j ° - š a Ÿ ° ° x expanding the plant will reduce the credit. A parent making the same mistake would look š ° ° x j ° © š £ a ¥ ° ± Ÿ j ° « ¢ ° ° x j ° š ° ° « 3 š a œ j ° š a Ÿ ° ¥ ¢ ° ¥ ° motivated to earn good grade ° j 2 j a ° ° x « ± £ x ° ° x j ° œ x ¥ up (or even if ° ° « 3 š a ° it goes down) when grades improve. ° ° ° x « ± £ x ° ° (j - x © « a ° s interpretation of economic ¥ a ° signals is hidden under layers of graphs and equations, its error is just this fundamental.

The problem is that, while Teshmont understands that locational price signals are related to locational price differences, Teshmont has not thought through the impact of investment on the loss factors. Since the Teshmont, 2011 report is focused on ILFs and the entire point of ILFs is to take account of the impacts of investments on loss factors, this is not a minor oversight. And it is not an oversight that is easily explained since (j - x © « ILF ° calculations are driven by the impact of investment on losses. Without such an impact, ILFs degenerate into MLFs as shown in Appendix 1. But while raw ILF calculations include the impact of an invest © j a ° ° « a ° ° « ° - ° j ° ° ° that Teshmont calculates do not include the impact of that investment on the ILF that the investor will receive.

This problem is seen most clearly in scenario 3 (Teshmont, 2011), with its 10 GW of load and generation that anchor both of the bus-2 loss factors (ILF and MLF/2) at zero. This

means that the difference between the bus 1 and bus 2 loss factors is always just the bus-1 loss factor, so we can concentrate our full attention on bus 1. (In fact, the Teshmont graphs, 4 and 11, do show the locational difference, but in case 3, this has no effect, as just explained.)

- 5 Teshmont looks at the magnitude of the loss factor at bus 1 and, if it is negative (a credit), it concludes there is a signal to invest. It makes no calculation of whether the credit will go up or down when the investment is made. So, sometimes Teshmont concludes that there is a signal to add capacity, even though this would reduce the credit received by the investor.

u *d Signals*

- 10 Teshmont (2011) asks: "Are there any cases where system losses are not zero? Teshmont is considering the case, among several, in which a 150-MW load and a 100-MW Generator are located together at the end of a long line. With load greater than generation, power is flowing into this area over the line, and there are losses. Another MW of local generation would reduce the losses on the incoming power, so
15 there is a loss credit for the 100-MW Generator at this bus. The generator is pleased.

- (The 100-MW generator is favoured with a correct locational signal; namely, a 2 percent loss credit. And, as just noted, it is pleased with this favour. So we have every reason to believe that the generator will indeed stay put,
20 just as it should.

Supposedly, the R-bus 50% Area Loss Factor Methodology This methodology is quite sophisticated. For example:

$$\alpha_a := \begin{cases} \frac{pg_2 + pgb_1 - \left(\frac{pgb_1}{v_1}\right)^2 r}{pl_2} & \text{if } pl_1 = 0 \\ \frac{\left[-\left(pl_1 + pl_2 - 2 \cdot pl_1 \cdot pgb_1 \frac{r}{v_1} \right) + \sqrt{\left(pl_1 + pl_2 - 2 \cdot pl_1 \cdot pgb_1 \frac{r}{v_1} \right)^2 - 4 \cdot \left(\frac{pl_1}{v_1} \right)^2 r \left[-pg_2 - pgb_1 + \left(\frac{pgb_1}{v_1} \right)^2 r \right]}{2 \cdot \left(\frac{pl_1}{v_1} \right)^2 r} & \text{otherwise} \end{cases}$$

But it seems fair to ask: inciting generators to stay put? Is that really all we expect from locational signals? When more generation is needed, should the locational signal simply the bus and keep the existing generator at the bus happy? Perhaps it does more. In section 3.3 Results (for MLF/2), Teshmont explains the locational signals that we are dealing with in this exact situation:

The locational signal for bus 1 (equal to the difference in loss factors between bus 1 and bus 2) is shown in Figure 4. When power is flowing from bus 2 to bus 1 signalling a need for generation at bus 1, the unit at bus 1 receives a credit for most of the loading conditions simulated and the unit at bus 2 receives a charge. [Emphasis added]

So again, we find the analysis undertaken limited to the fact that the unit at bus 1 receives a credit. But, also, (It is a negligible charge in scenario 3.) It may be that there is some hope that this signal will cause the unit at bus 2 to move to bus 1. But this cannot be, because if and when the unit does move it will not receive the credit that Teshmont has calculated for bus 1. Instead it will receive a far lower credit and perhaps a charge. So the unit will simply turn around and go back to bus 2.

In other words, ut instead, for the unit at bus 2 it is equal to the difference between the loss factor that would be given to bus 1 if the unit from bus 2 moved there and the loss factor at bus 2. As we will see this is not a small matter in the examples under consideration by Teshmont.

But skeptics may insist that Teshmont is being unrealistic if it is attempting to get the unit at bus 2 to move. So perhaps Teshmont was considering some other generator that is waiting for a chance to be built at either bus 2 or bus 1. But in this case, the locational signal does

not involve either of the two loss factors that Teshmont is subtracting to find its signal. Instead the actual signal depends on the two loss factors that Teshmont would calculate (but did not) if this new generator were to locate at bus 1 or bus 2.

5 So the conclusion must be that the signal Teshmont has calculated, or rather the half of the signal at bus 1, which is providing a credit to the unit located there, will send a sort of locational signal. That credit will succeed in getting the unit to
10 simply does not apply to any new investment at bus 1.

U 7 #

Teshmont has made a large number of graphs of load factors and signals, and it would take
10 too long to review them all. But they all rely on the same method of calculation. Teshmont
Figure 4 is the basis of the claims just discussed, and Teshmont Figure 11 is the analogous figure for ILF. Each figure covers three scenarios, and I have picked the simplest one based on the theory that if the simple one is wrong, the more complex ones will likely also be wrong. In the simplest scenario (#3), bus 2 has 10,000 MW of both generation and load, and
15 since they are at the same bus there is no loss from transmitting power from bus-2 generation to bus 2 load. This means that raw loss factors and the shifted, final, load-flow loss factors at bus 2 are essentially zero. So the difference between the loss factors at bus 1 and bus 2 are essentially just the loss factors at bus 1. In other words in this simple scenario (#3) bus 2 can essentially be ignored.

20 (j - x © « a ° compares MLF/2 (Teshmont Figure 4) with ILF (Teshmont Figure 11), so I have reproduced the simple scenario-3 curves from these two figures together in my Figure 5 below.

generation) is assumed to be held constant at 100 MW at bus 1. Hence the upper horizontal axis shows a range of generator capacities from 0 to 200 MW. Since loss factors are determined by power flows rather than by either load or generation separately, this change in the horizontal axis has no effect on its calculated-loss factors.

Table 1 in Section 6 presents a Comparison of Methodologies, and two rows in this table check the locational signals of MLF/2 and ILF. These two rows (row 2 and row 3) contain the only economic conclusions in the report, so we will check them carefully.

Teshmont Row 2 of Table 1 (p. 17):

Comparison: Does the methodology give a logically correct locational signal if there is no flow hence no losses on the circuit?

Current Methodology: Yes, the locational signal is zero. (Figure 4)

Incremental Loss Factor: No the locational signal favours the smaller unit. (Figure 11)

The relevant points in Figure 5 are marked by arrows 1 and 2. In both cases there are no losses. As always the signal that Teshmont calculates applies to the existing generator. Since it is the right size, the view is apparently that the right size is right (Teshmont, 2011, Section 3.3), because that will keep the plant just where it is. There are two problems with this view:

1. Any signal at all will keep the plant where it is.

2. The calculated signal for new investment is zero.

Point two deserves close attention. Signals are economic incentives and economic incentives, like motivational allowances for children, are conditional payments. In the simplest case, the payment can be conditioned only on the location of an investment. But for every example analyzed in Teshmont report, the payment depends on both the location and on the size of the investment. If this were not the case, then as shown in Appendix 1, ILF would just be MLF because the first and last MW would have the same marginal loss. In fact the whole point of ILF is to take account of the fact that loss factors depend on the size of

the investment and on the output of the plant. Forgetting the central element of conditionality means that () misestimated;

5 This does not mean MLF/2 does not provide signals. It does provide signals. But the signal is not contained in the two values at different locations under one set of circumstances. In these examples, the signals from MLF/2 come mainly from how it changes when an investor or a plant operator does something such as investing or producing more power. That signal cannot be extracted without specifying that change, and calculating the payment before and after the change. That can be done for MLF/2 just as easily as all other calculations. The point is that it has not been done. So Teshmont and the AESO have
10 no idea of whether the MLF/2 signals are good, bad or indifferent.¹³

One reason they have failed to find the signals is that they have not focused on investment. There is nothing in the report that indicates who is being signaled or what exactly they are being signaled to do. The words investor and investment are nowhere to be found.

As noted above, Teshmont links power-flow the independent, X-axis variable to changes
15 in load. This is inconvenient for a study of investment incentives, but would be well suited to studying how load relocates due to loss factors (if that were of interest). However, a change in the 100 MW of generation capacity at bus 1 (which is nowhere contemplated in the Teshmont report), would have the same impact on the power flow as a change in load, and hence the same impact on the load factors.¹⁴
20 flow axis as generation capacity and this is shown on the upper X-axis.¹⁵

Returning to the comments in Row 2 of Table 1

Teshmont under MLF/2, and there is no loss, the signal is logically correct. But what if the owner of the existing plant reduced its capacity, or more likely, simply reduced its production? What if it
25 produced only 75 MW instead of 100? That would increase its loss credit from zero to 1

¹³ Though to be fair, in other circumstances, the non-signals they calculate can be quite close to the real signals when the relevant investment/output changes are small relative to the power flows on the local lines.

¹⁴ Note that this is only true for scenario 3 (the one under discussion) because in that scenario the load-weighted swing bus does not change significantly when the load at bus 1 changes. The load-weighted swing bus is essentially always bus 2 in scenario 3.

¹⁵ This has also been done for Figure 1.

percent, in other words, by 0.75 MW. This may not be worth its while, but the point is that MLF/2 is providing an incentive for this plant to reduce its output, which will require importing more power from the system, and that will create losses. But what if the unit is increasing losses? It is not correct, Teshmont

5

thus got its first economic conclusion wrong (see also Figure 4).¹⁶ Teshmont

Next consider the ILF incentive (arrow 2 in Figure 5). Teshmont sees the ILF loss credit of 4 percent and concludes that the signal favours the smaller unit, something it feels is not logically correct. ILF also favours the smaller unit, doing the unit a favour. But that is not an incentive to do anything. ILF also favours the unit's existence over its non-existence, which means it sends this unit a signal not to retire. And this is a good thing. If it retires, losses will increase. So ILF passes this test.

10

But what about other possibilities? What if the unit decided to expand to 125 MW? That expansion would increase losses, and it would still get a loss credit. No. What matters is the change in payment. Since investors cannot bank a percent, and they must bank dollars, the relevant change is the payment change.¹⁶ Before the expansion, the loss credit is 4% of 100 MW or 4 MW (which gets multiplied by the pool price and turned into dollars). After the expansion, the loss credit is 3% of 125 MW, or 3.75 MW, which is less, so the expansion is discouraged, just as it should be.

15

So ILF discourages retirement and it discourages expansion. In fact, it discourages any change, and that is efficient, because losses are zero and any change will increase them. So ILF pushes in the right direction, but does it push with the right force? In fact, as explained in the discussion of Figure 4, ILF has exactly the right strength to induce optimal investment. In this case ILF is the change in losses from zero caused by the investment. If an investor increases losses from zero to X MW, ILF assigns it a loss factor of X MW or increases its loss factor by X MW. That is precisely correct.

20

25

I will not go through all of the other expansions and contractions the owner of the generator at bus 1 could make, but they all work out correctly, so Teshmont also got its second economic conclusion wrong (see also Figure 4).¹⁶ Teshmont

¹⁶ Teshmont's error is about the agent being signaled.

Teshmont Row 3 of Table 1 (p. 18):

Comparison: Is the locational signal logically correct when system losses are not zero?

Current Methodology: Yes, the locational signal favours the bus where there is a shortage of generation (excess of load). (Figure 4)

5 **Incremental Loss Factor:** No, there are some dispatch conditions where the locational signal favours a bus where generation exceeds its local load. (Figure 11)

In the MLF/2 case (arrow 3), there is too little generation so the locational signal should call for more. As can be seen from Figure 5, the loss credit is 1%, and 25 more MW are needed.

10 So Teshmont says the bus should be pleased with this favour. But if the locational signal for an investor to build more?

Suppose an investor builds a tiny 25 MW plant that is just the perfect size? The AESO will surprise it by switching to a zero loss credit. That would be bait and switch, except there is no investor foolish enough to take this bait. There is no signal at all to build the ideal investment. So Teshmont got its third economic conclusion wrong

15

In the ILF case (arrow 4 of Figure 5), there is too much generation by 25 MW, and Teshmont says

20

much generation. Does an ILF signal the extra generation to leave? As before, we check how the loss charges/revenues change if the generation owner takes an action (and we do not check the static percentage favouring the bus).

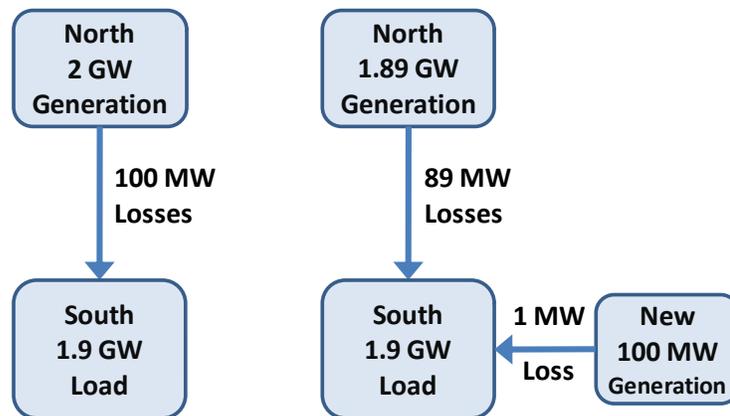
If the investor could reduce capacity or output from 125 MW to 100 MW, its ILF payment would change from 2% of 125 MW to 4% of 100 MW, which is to say from a 2.5 MW credit to a 4 MW credit. In other words, there is quite a strong signal for 25 MW of output or capacity to walk away. Accordingly, Teshmont also got its fourth and final economic point

25 wrong

4. Why Not to Divide by Two: An Example

Alberta has, in the past, been concerned with locational signals for generation to locate in the South and reduce the need for new North-South transmission. Hence it makes sense to look at the most basic of such locational-incentive questions. Suppose there are only two buses, one in the North and one in the South of a system. Suppose there are 2 GW of generation in the North and 1.9 GW of load in the South and losses are 5 percent. Now suppose a 100 MW generator locates in the South at a third bus and has a 1 percent loss when delivering power to the Southern load. It will cause a 1 MW loss, but it will save 11 MW of loss on the North-South line (the saving is marginal, which is about twice the average).¹⁷ We see these scenarios in Figure 6 below.

Figure 6. The Effect on Losses of a New Generator



Clearly, the new generator has reduced average system losses by a lot, and should receive a credit for doing so. But the MLF methodology, and hence also the MLF/2 methodology, traces power flow to load, and on that wire there are losses. It does not consider its effect on Northern generation. Its marginal loss on the wire in the South is 2 percent and so MLF/2 will charge the new generator for a 1 percent loss factor. The AESO will argue that the new generator is losing exactly 1 percent of its power, so this is perfect. But that completely ignores the 11 MW of losses from that North more than ten times its

¹⁷ Losses are reduced by a bit more than 10% of the reduction in northern generation because when the 100-MW generator moves south, it has smaller losses and delivers more power to load than when it was in the north.

« 3 losses that the new generator eliminated by locating where it did. Is this reasonable, as required by the Regulations?

It would seem not, but perhaps it is inevitable. To test this, consider another technique, besides dividing by two, for making loss charges match actual losses. Suppose we were to consider a different arithmetic operation subtraction, instead of division. Marginal losses are calculated the same as before, but this time we subtract average system losses of 4.5 percent.¹⁸ Using this value and the MLF Raw values from Table 6, gives us loss factors of 5 percent (9.5% in the North and minus 2.5 percent (2.0% for the new
 5
 10 seems much more reasonable than a charge of 1 percent for such a good deed. And, as Table 6 shows, under MLF/2, the new generator that did so much to reduce losses would, in fact, receive a 1 percent loss charge.

Table 6. MLF/2 versus MLF Shifted

	Original Dispatch			With New Southern Generator		
	MLF Raw	MLF/2	MLF Shifted	MLF Raw	MLF/2	MLF Shifted
North	10.0%	5.0%	5.0%	9.5 %	4.7 %	4.9 %
New South	0.0%	0.0%	0.0%	2.0 %	1.0 %	2.5 %

The shift factor is average losses or about 5 percent

But again, economics is not concerned with appearances. The question is which method works better? The locational signal is proportional to the difference between the Southern
 15 loss factor if the new generator locates in the South and the Northern loss factor if the generator locates in the North. In the MLF/2 approach this is 5.0% (MLF/2 in the North) minus 1.0% (MLF/2 in the South with a new generator), which gives a 4% locational signal from MLF/2. Under the standard MLF approach this is 5.0% (MLF Shifted in the North) minus 2.5% (MLF Shifted in the South with a new generator), which gives a 7.5%
 20 locational signal from MLF. So the locational incentive is nearly twice as strong in the standard, MLF, approach as in the current, MLF/2, approach. But is that right?

¹⁸ Average system losses are total losses (89+1) divided by total generation (1.89+1.90+0.1), as shown in Figure 5.

Stronger is not necessarily better, and economics looks for the best signal the one that saves the most money. The new generator reduced North-South losses by 11MW (100 - 89), but increased them by 1 MW in the South. Suppose the cost of replacing losses is \$50/MWh; then the new generator saved $(11\text{MW} - 1\text{MW}) \times \$50\text{MW/h} = \$500/\text{hour}$ by reducing losses.

5 But it was rewarded by only a 7.5% lower loss factor on a 100 MW generator, which saves the new generator $7.5\text{MW} \times 50 = \$375/\text{hour}$. The stronger (standard) MLF incentive is still a bit weak, but it is far better than only half that much, which is the signal from MLF/2. It is too weak partly because this is an incremental change and ILF would be more appropriate.

10 Before summing up, it should be pointed out that this is not some odd example cooked up to make a point. This is the most obvious first example to try in Alberta. In the past the AESO has spent money incenting generators to locate in the South instead of in the North. And one must therefore question why this example has not been reported on in detail before?

15 In any case, the conclusion must be that the MLF/2 approach *charges* the investor who reduces losses following the folk wisdom that no good deed goes unpunished. It also provides less than half the locational price signal that it should provide. And it does these things either because there was thought to be some value in ignoring basic economics (competitive price equals marginal cost) or because of a preference for dividing by two instead of subtracting. Although it is easy to imagine worse approaches than MLF/2 (for example, MLF/3), MLF/2 does seem to fail the most obvious tests of reasonableness.

5 Harming the Benefactors; Helping those Who Cause Losses

This example differs from the previous one in that it takes account of the existence of some Northern load in Alberta, which gives Southern generators a loss *credit* under MLF/2.

When a wind turbine generates in the South, some power flows to Northern load, or causes
5 Northern generators to produce less for the South. In any case, losses on the north-south
line are reduced, and the wind turbines are given some credit for reducing losses. Suppose
this

Now when one thinks of dividing losses by two, because twice too much loss revenue is
being collected, it is easy to think that all generators are being helped proportionally. But
10 this is not the case. The generators causing the trouble (i.e. creating losses) are helped in the
same proportion as the generators causing the benefit (i.e. those reducing losses) are hurt.
The Northern generators have their charges cut in half (being helped in this fashion) and
the Southern generators have their *credits* cut in half (being harmed).

if at all, to system losses, in
15 short, to be fair, this result would appear anything but. Alternatively, if the point is to reduce
over-collections, why not just cut the charges (causing the over-collection) in half? Cutting
credits in half actually increases the over-collection problem. Cutting just the charges would
mean that dividing by some number smaller than two would be required. Fortunately, with
modern computers, numbers like 1.763 can be handled quite easily. But is there some
20 reason that loss-reducing units, for example, wind turbines in the South, should get their
loss *credits* cut in half?

Is it possible that their marginal loss is 2 percent, but their average loss is quite different
and deserves only half the reward indicated by the marginal loss? No, because wind
turbines (and even wind farms) are bit players, and the flow on the north-south line is huge.
25 They have little impact on losses as their output changes. If their marginal loss is 2 percent,
their first, middle and last megawatt all save about 2 percent. So taking away half of their
credit (1) makes the problem of over-collection worse, (2) does not reflect at all their
contribution to loss reduction, and (3) has never been shown to improve any loss signal. It
really just comes down to numerology: two is a sort of magic number if you apply it to

everyone, whether it makes sense or not, it gets rid of over-œ« ¨ ¨ j œ° ¥ « ª ¨ ¨ Š ª Ÿ ¨ ° ¨ j ©
to figure out the less auspicious number that would do the job without punishing good
deeds.

5 The situation is more complex with larger units, but the same principle holds. Generators
that reduce losses are harmed by dividing by two, while generators that contribute to losses
are helped. This point was made quite clearly by Milner in its complaint of 2005.

10 *The MLF/2 approach does not accurately or fairly reflect the benefits derived from
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.*

This point rests on nothing more complicated than the fact that helpful generators have raw
loss credits and dividing by two harms them, while dividing a charge by two helps the
generator causing losses.

15

6. Why Over-Collection Is Not a Problem

Section 3 of this report discusses over-collection and makes the point that, with or without over-collection, generators will pass the average transmission costs through to load. What will remain with the generators are the variations in transmission costs (around the average) that send the loss-pricing signals. But the average transmission cost will not be passed through with absolute precision and Table 7

Table 7. Payment and Short-Run Pass Through of Total Loss Costs, *LC*

	MLF	MLF/2	MLF SF
Charge to Generation			
Pass Through to Load			
Net Cost to Generation		/2	

The main thing to notice is that dividing by two does not get rid of some unfair burden on generators, simply because the over-charge is passed through to load. What MLF/2 does is to cut any error in half simply because it cuts everything in half; both the signal and the noise.

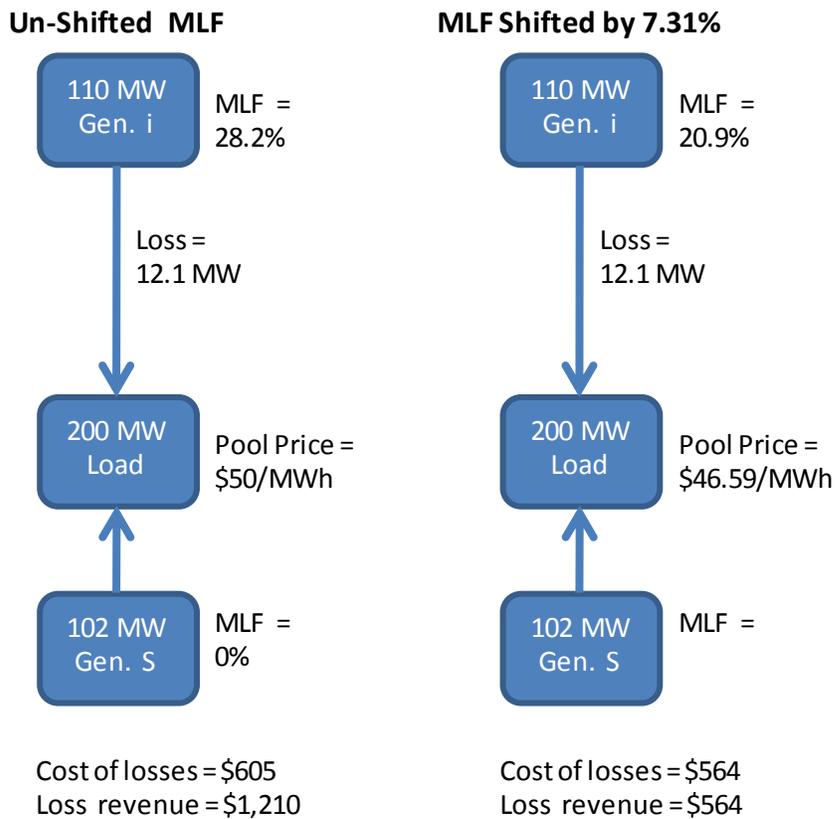
Because there may be some correlation between price-setting plants and their loss charges, the pass-through will be slightly more or less than 100 percent (There are several reasons not to worry about this epsilon of uncertainty:

1. It will likely be quite small compared with loss charges.
2. No one knows whether it will be plus or minus.
3. It will change over time.
4. Compared with the uncertainty in the annual-average spot price, this uncertainty is extremely small.
5. Investors will soon correct for any profit deviation caused by epsilon if it brings extra profits, they will invest more, and if it lowers profits, they will invest less. (Of course this effect too, will be lost in the noise, which just proves it does not matter.)

Our best estimate is that there will be 100 percent pass through. We know that is what happens in competitive markets on average. What matters is getting the loss signals right so that generators and investors will make efficient decisions. The intent is to design an efficient market, and the market's job is to take care of any epsilons that result. That is what markets do, and do very well. And most of the epsilons they deal with, such as swings in the price of gas or other inputs, are vastly larger.

As discussed, with or without over-collection, generators will pass the average transmission costs through to load. In spite of this, it is possible to shift loss factors such that over-collection does not occur. The next appendix works out the theory of doing that perfectly. Perfection is not necessary, but it is reassuring to see that loss-factor shifting has a firm theoretical basis. An example of such a shift is presented below, but the calculations for it require formulas from the next appendix.

Figure 7. Efficient Loss-Factor Shifting. (Loss = $G_i^2/1000$)



Using the formulas given at the end of the next appendix, generators are paid exactly the same price (including loss charges) for their power before and after the shift. Consequently they will supply exactly the same amount of power. Since the un-shifted dispatch is efficient, so is the shifted dispatch with no over-collection. Of course, since generators are paid
5 exactly the same amount (lower pool price and lower loss charge), they do not benefit from the shift. The over-collection is passed through to load via the lower pool price. But then load does not benefit from the over-collection. Nothing really changes. What is important is that through the use of a shift factor (rather than dividing by two) we have been able to lower the total revenue collected so that it now equals total losses and have been able to do
10 so without unfairly benefiting those generators harming the system at the expense of those generators benefiting the system.

7. The Theory of Shifting Marginal Loss Factors

5 It is not hard to shift loss factors down to reduce the revenue collected by the AESO. But if it is not done carefully it may cause a slight problem. For example if at two locations the loss factors are 10% and 5% and they need to be shifted down by 4%, it would seem that simply subtracting 4% and arriving at 6% and 1% would be perfect. The locational signal would be unchanged because it depends on the difference, which remains 5%. However, shifting loss factors down causes generators to bid lower prices in the spot market, so the pool price is changed. This can cause a slight change in incentives.

10 However, there are at least two ways to define a loss factor as a percentage of power injected, or as a percentage of power delivered (after losses). As this appendix will show, if the more common definition (the percent of power injected) is used, then subtraction causes a subtle change in the locational signal, and a slight correction is needed. But if loss factors are defined as a percent of power delivered, subtraction works perfectly. The effect is small enough that a mismatch of loss-factor definition and shifting technique would be of
15 little consequence. But it will be instructive to work through the exact theory of loss pricing, shift factor definitions, and shifting methods for Alberta's single-pool-price market. The theory of loss factors has previously been developed rigorously only for markets with locational pricing. Although only marginal loss factors will be analyzed, since incremental loss factors can be calculated from MLFs, the results should apply to ILFs as well.

20 *Loss Factors Can Reproduce Locational Marginal Pricing*

Competitive prices depend on supply and demand and that varies from bus to bus when there are transmission constraints, but such locationally distinct (competitive) spot prices are not allowed in Alberta. Instead, a uniform pool price is mandated, which causes rationing on the upstream side of constraints. Rationing is a typical result of price controls.

25 Contrary to the ban on locational congestion pricing, locational loss pricing has been mandated. Nominal pool prices must still be uniform, but locationally distinct loss factors have been required and these, in effect, modify the pool price at every location and create supply-side locational marginal prices. In fact, as will be seen, it is possible to reproduce standard LMPs exactly, at least as far as losses are concerned.

The Loss-Factor Payment Formula

Usually, it is thought that a generator will be required to pay λ_i per MWh injected. And, this is, in fact a very good formula and far better than P , but it is not quite ideal, because the pool price, P , as just noted, is not quite the effective price. A slight modification
 5 of this payment formula will cause everything to work out nicely. I will make that modification now, and then show that everything works out as we would hope it would.

$$\text{Loss charge per MWh injected} = \lambda_i - P \quad (5)$$

With this change, generators will pay the cost of replacing loss at their own bus. This makes sense because, if they replace the losses physically, the value of the replacement power
 10 would be the effective price at their bus.

Finding the Effective Nodal Prices with Loss Factors

The next step is to find what the effective price should be. For these prices to send efficient price signals to generators, the effective prices must be in the same proportion as the nodal prices described above. So we begin by selecting a swing bus, which, by tradition, we will
 15 make the load bus. Loss factors will be computed relative to this bus, so the loss factor at the swing bus is zero. The effective price at a bus is just the pool price adjusted by loss payments. Since loss payments are zero at the swing bus, the effective price at the swing bus, λ_i , is exactly the pool price, P . Using this fact with Equation (4) gives:

$$\lambda_i = P - \sum_j L_{ij} \lambda_j \quad (6)$$

20 This allows us to re-write Equation (5) as:

$$\text{Loss charge per MWh injected} = \lambda_i - P \quad (7)$$

And this will allow us to find the loss factors that will produce the effective prices that will lead to an efficient dispatch. Recall that the effective price that a generator is paid is just the pool price minus the loss charge. Hence,

$$\lambda_i = P - \sum_j L_{ij} \lambda_j \quad (8)$$

Combining this with Equation (6) and canceling the pool price gives,

$$\lambda_i - P = - \sum_j L_{ij} \lambda_j \quad (9)$$

which can be solved for λ_i to find,

(10)

This formula allows us to determine the loss factors by using the loss properties of the network as captured by the transmittance from bus to the swing bus. However, we were expecting a standard formula for , such as the percentage of power lost. So this formula
 5 needs interpreting. Letting L be total system losses, the standard loss factor formula is
 , in other words the change in losses as a fraction of the extra power injected and sent to the swing bus. But why not consider loss as a fraction of delivered power instead of sent power. For losses in the normal range there is not much difference, but there is also no strong reason to prefer one to the other. Delivered power is what really matters, so we will
 10 take a look at that possibility and worry about the reason for this choice later. Remembering that decreases when increases, we define,

$$\frac{\Delta L}{L} = \frac{\Delta P_{in}}{P_{in}} \quad (11)$$

The formulation using deltas is just an approximation to help with intuition. Total losses are just the sum of all power injections since withdrawals show up as negative injections. Also
 15 recall that when using the swing bus, no injection changes except for the two buses in question, so . So we have

$$\frac{\Delta L}{L} = \frac{\Delta P_{in}}{P_{in}} \quad (12)$$

But in Equation (3) was defined to be , so using this definition and Equation (12), Equation (11) simplifies as follows:

$$\frac{\Delta L}{L} = \frac{\Delta P_{in}}{P_{in}} \quad (13)$$

Which is the same as Equation (10) and shows that our definition of the loss factor, as losses as a fraction of power delivered, is the definition [in Equation (10)] that is needed to induce an efficient dispatch when losses are charged according to Equation (5).

Shifting the Loss Factors Maintains Efficiency

25 The last step is to check that shifting loss factors does no harm. As noted at the end of the subsection on nodal pricing, refunding the over-collection of losses could introduce a subtle inefficiency in relative prices. That needs to be checked in the pool-price context as well. But

8. Do Existing Plants Need Locational Signals?

It is difficult to move an existing power plant by even a few feet. Accordingly the question has been asked: why should existing plants be subject to locational price signals?

5 immediately after its concise articulation of the twin objectives of loss pricing (repeated here for convenience):

Loss signals should provide an appropriate economic signal for optimal system dispatch.

10 • *Loss signals should provide the siting of appropriate new generation.*

The Board considers both of these two objectives to be desirable and important in a restructured deregulated environment for generation. However, the Board has some reservations that one loss factor, no matter how well designed, would be able to optimally achieve both objectives[Emphasis added]

15 While the Board was justified, one price signal should, in fact, come remarkably close to achieving both objectives. This is a standard result of the economics of competitive markets. And this provides one answer to the question of why existing power plants should receive locational signals. The answer is that the locational signals are also the signals that

20 tell existing generators how much power to generate. And PJM (2007a) estimated that this use of the signal would save \$100 million a year.

This classic economic result, that one price can serve two functions optimally, underlies the entire theory of competitive markets. It is not easily proven and consequently its proof resulted in a Nobel prize for Kenneth Arrow in 1972, and another for Gerard Debreu in

25 1983. So I will not attempt to summarize this proof. However, the result, in general terms is that a competitive market, which prices goods and services (but does not charge consumers or business multiple prices for the same item) will result in optimal production and optimal consumption, And, of course optimal production is not possible unless suppliers invest

optimally in the right plant and equipment and that includes the location of the plant. In other words, the competitive price for electricity (which would take into account losses) would not only signal the right level of production and the right location, but would provide a myriad of other signals optimally. It would signal what types of plants should be built, what fuel should be used, what type of wire should be used in the actual generators. For some reason most of this is taken for granted. No one suggests that we need separate price signals for all of these aspects of producing electricity. Indeed the popular mantra is that an
5 sudden worry that one price cannot possibly do two things at once. Fortunately, one price (that varies over time) can and does do many things at once, and locational signaling is just one of these many things. So all that is needed (at least under competitive conditions), is to correctly include the cost of transmission in the price of electricity and this is done by charging generators the marginal cost of losses, just as they are charged the marginal cost of fuel, wires, concrete and all other inputs. This is why an electricity market is a good idea.
10 The right price does the whole job.

To give is only one grade of gasoline). One price of gasoline must signal where stations should be located, when they should be open, how many pumps to install, and of what quality. On top of that, the same price must signal to consumers how much gasoline they should buy and give them the correct incentive for buying a Prius. If one price could not do many jobs well competitive markets would be in deep trouble and we would need regulators to send special signals concerning almost everything.
20

Now let us return to the question of existing plants. First they need the same loss prices to signal an optimal system dispatch. But also note that investors respond only to signals that continue after their investment comes into existence. And, they are not interested in loss charges or credits that they receive only for a week or two. So to send location signals to investors, we must send them to all existing plants built *after* the locational signals are implemented. So if they are not sent to pre-existing plants, then for decades to come there will be two classes of existing plants: ones with loss signals and ones without loss signals.
25 Since these signals are valuable or costly, one group or the other will feel short changed (perhaps justifiably so) and will complain.
30

9. How Not to Analyze Price Signals

In its October 18, 2005 report, *2006 Transmission Loss Factor Methodology Decision Document*, ATCO considered three basic cases (1, 3, and 5) as well as two variants cases (2 and 4) that demonstrated that changing line impedance or system size did not affect its analysis of the remote region. The remote region was connected to the system by a transmission line and it contains a 100 MW load in Cases 1 and 3, and 25 MW of load in Case 5. Various sizes of remote generators were considered, but in Case 1, the remote generator was 100 MW, as shown in Figure 8.

Figure 8. Case 1



10

In each case both ILF and MLF/2 are calculated. ILF is based on losses before a 50 MW increment of generation at remote Bus 2 and losses after the 50 MW increment (from 50 MW up to 100 MW). Marginal losses are based only on the character of losses for the last or 50th MW of the increment, or, more accurately, for the last (marginal) Watt of the increment of generation. The marginal loss at this point is the rate at which losses are increasing. As will be seen, they are often increasing (or decreasing) at a rather different rate for the last Watt than for the first Watt or for any of the in-between Watts.

15

In each of the three diagrams below (for Cases 1, 3, and 5) two arrows are shown. One indicates the change in losses actually caused by the increment of generation (the ILF arrow). The other (the MLF/2 arrow) shows the losses that would have been caused by the entire increment of generation had that entire increment had an effect measured by MLF/2.

20

Each case demonstrates first, that the ILF approach sends the right price signal; second, that MLF/2 sends the wrong price signal. In cases 1 and 5, the AESO has misinterpreted both price signals.

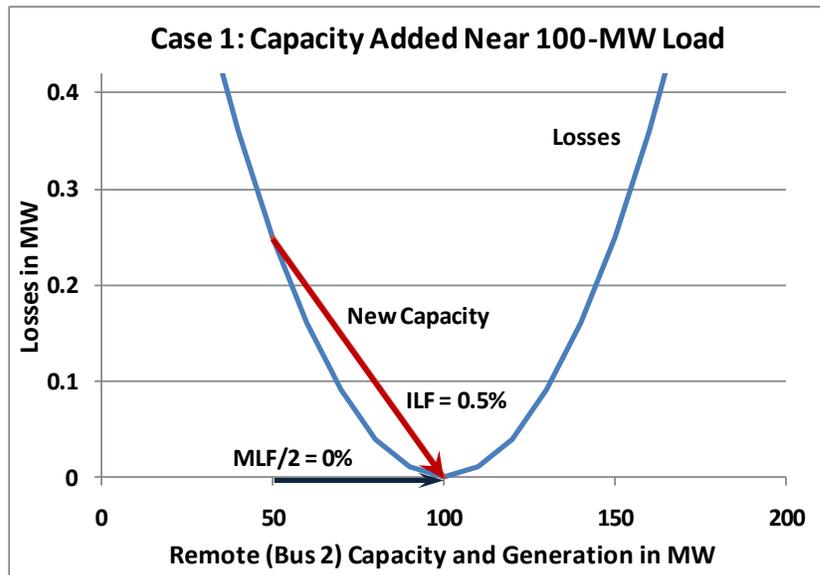


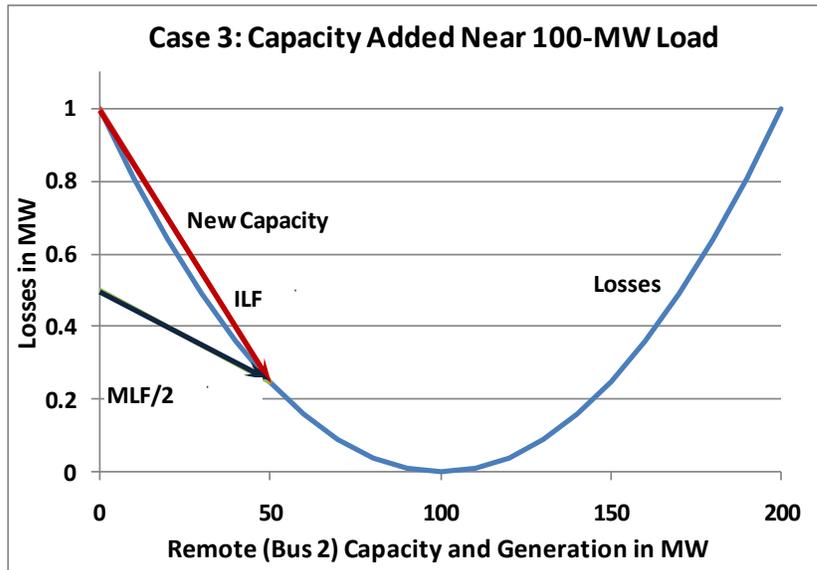
Figure 9.

In Case 1, 50 MW of new capacity is added at the remote Bus 2 to bring total capacity up to the 100-MW load, so there is no power flow on the line and there are no losses. With no losses (at the bottom of the loss curve), losses are neither increasing nor decreasing with generation, so marginal losses, MLF, and MLF/2 are zero.

The incremental losses of the new capacity are $IL = 0.25 \text{ MW}$. So the Incremental loss factor is $ILF = (0.25 \text{ MW}) / (50 \text{ MW}) = 0.5\%$.

The AESO interprets ILF saying, "where the generation and load are balanced at Bus 2, the signal (-0.5%) encourages new generation at Bus 2, when in fact new generation at Bus 2 [the load system center] beyond 100 MW. But this means the AESO is assuming $ILF = 0.5\%$ is the price signal for the next increment of generation beyond 100 MW. But that increment will increase losses and get a positive ILF (a charge) instead of a negative one (a credit). So investment ILF, they will in fact be encouraged to locate at Bus 1 by their anticipation of ILF."

not encourage this loss-reducing capacity addition (from 50 to 100 MW). ILF sends the right signal, MLF/2 sends the wrong signal, and, as noted, the AESO has misread both signals.



5 **Figure 10.**

In Case 3, 50 MW of new capacity is added at the remote Bus 2, which previously had no capacity. The MLF/2 arrow shows losses declining at exactly half the rate of the actual loss curve at the marginal Watt of capacity – the end of the 50th MW. The MLF/2 approach does credit this capacity with a loss reduction, but only with one third of the actual reduction.

10 ILF differential signal (-1.5%) encourages new generation at bus 2

In this case we cannot be sure what new generation will be added at bus 2, but it is clear that the ILF signal is more accurate. That seems unusual given that one is three times as strong as the other. It is as if all that mattered was direction.

15 accurate. That seems unusual given that one is three times as strong as the other. It is as if all that mattered was direction.

In fact the ILF sends the right signal, MLF/2 sends the wrong signal. For an investor considering a new 50 MW generator starting with 0 MW of generation at Bus 2, the MLF/2 signal is actually three times too weak.

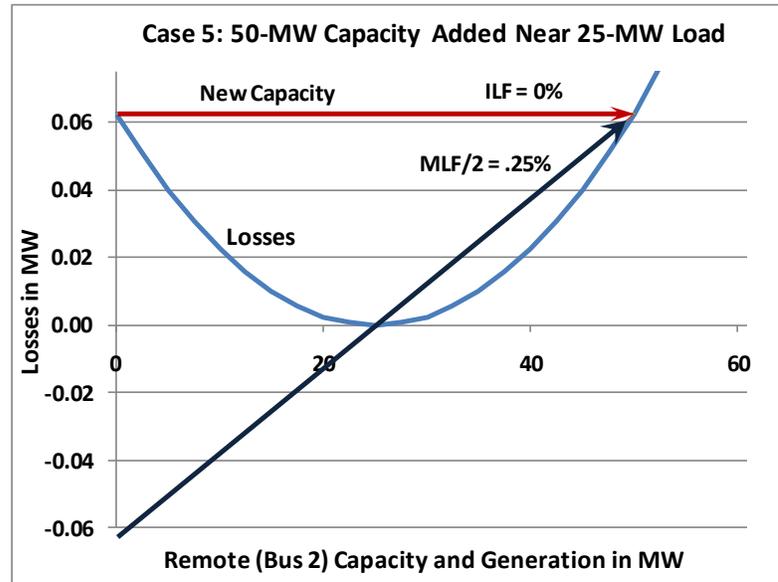


Figure 11.

In Case 5, 50 MW of new capacity is added at the remote Bus 2, which this time has only 25 MW of load. Consequently the 25 MW inflow reverses and becomes a 25 MW outflow to the system. Obviously there is the same loss in either direction, so the generator neither increases nor decreases losses. As a consequence, its ILF is zero.

The MLF/2 arrow shows losses increasing at exactly half the rate of the actual loss curve at the marginal Watt of capacity the end of the 50th MW. The MLF/2 approach charges the generator with this rate of increase from its first MW of output. This is quite a hefty loss charge and it would be quite discouraging, and needlessly so, for the generator in question.

greater than the load at bus 2. The difference in R bus (50% Area Load Adjustment) loss factors between the two buses (0.3%) [R-bus is 0.3%, but MLF/2 is 0.25%] would discourage additional generation at bus 2 and encourage additional generation at bus 1.

value and thinking this value will correctly discourage more generation beyond 50 MW at bus 2. But the value the AESO cites applies not to additional generation beyond 50 MW, but to all generation starting from 0 MW, which was half helpful and did no net harm. Never in

this analysis does the AESO figure out which increment of generation the price signals apply to.

However in case 5, where generation exceeds load, there is no signal; we believe new generation should in fact be discouraged at bus 2.

5 + new generation should in fact be discouraged at bus 2 (AESO, 2006, p. 47)? The only reasonable explanation is that the AESO is considering new generation beyond 50 MW. But this means the AESO is assuming a very strong price signal at 50 MW. It will depend (as it should) on the size of the next increment of generation investment, and it is the ILF that will apply to that increment of generation starting at 50 MW. This increment will be strongly discouraged, as it should be.

Once again the MLF signal is inappropriate (for the first 50 MW of generation), the ILF signal is just right, and the AESO has misread both signals.

Conclusion

15 The essential problem demonstrated in this appendix is the problem with the analysis. The AESO consistently interprets current loss charges as applying to future investments that will change losses dramatically. What investors respond to is the charges they will face once they build a plant. Those are the signals the AESO should have been analyzing but never did.

Furthermore, the AESO shows no inclination to go beyond directional signals and ask whether signals are too strong or too weak. But this may explain why arbitrarily dividing by two has never raised an eyebrow at that AESO.

20

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