

**NEW BRUNSWICK  
ENERGY AND UTILITIES BOARD**

**IN THE MATTER OF** an Application Dated  
June 30, 2010 by New Brunswick System  
Operator for Approval of Changes to the Real  
Power Loss Factor Methodology in the Open  
Access Transmission Tariff

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**REVISED EVIDENCE**

**December 3, 2010  
Volume 1 of 1**

**(This Evidence Supersedes that of June 30, 2010)**

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**NEW BRUNSWICK ENERGY AND UTILITIES BOARD**

**IN THE MATTER OF the Energy and Utilities Board Act, Chapter E-9.18,  
R.S.N.B., 1973, as amended**

**- and -**

**IN THE MATTER OF an Application Dated June 30, 2010 by the New  
Brunswick System Operator for the Approval of Changes to the Real Power  
Loss Factor Methodology in the Open Access Transmission Tariff**

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## **NEW BRUNSWICK ENERGY AND UTILITIES BOARD**

**IN THE MATTER OF an** Application Dated June 30, 2010 by the New Brunswick System Operator for the Approval of Changes to the Real Power Loss Factor Methodology in the Open Access Transmission Tariff

### **A P P L I C A T I O N**

#### **WHEREAS:**

1. New Brunswick System Operator (“NBSO”) is required pursuant to Section 111 of the *Electricity Act*, chapter E-4.6, R.S.N.B., 1973, (the “Act”) as amended to make application to the New Brunswick Energy and Utilities Board (the “Board”) for approval of changes to the Open Access Transmission Tariff (the “Tariff”); and
2. NBSO has filed supporting Evidence with this Application; and

**NOW THEREFORE** NBSO applies to the Board for the following:

- a) An Order approving changes to the Tariff, incorporating monthly updates to the Real Power Loss Factor, pursuant to Section 111 of the *Electricity Act*,
- b) Consideration of a written proceeding in accordance with the following schedule; and

<b>NBSO Files Application and Evidence</b>	<b>Wednesday, June 30, 2010</b>
<b>EUB Notice (e-mailed by NBSO to Market Participants, Transmitters, Market Advisory Committee, and Interested Parties from the most recent NBSO Hearings)</b>	<b>No later than Thursday, July 8, 2010</b>
<b>Deadline for Intervenor Registration and Comments in relation to NBSO's request for a Written Proceeding</b>	<b>Tuesday, July 13, 2010</b>
<b>Interrogatories to NBSO</b>	<b>Tuesday, July 20, 2010 (Noon)</b>
<b>Responses of NBSO to Interrogatories</b>	<b>Tuesday, July 27, 2010 (end of business day)</b>
<b>Intervenors File Evidence</b>	<b>Monday, August 9, 2010</b>
<b>Interrogatories to Intervenors</b>	<b>Thursday, August 12, 2010</b>
<b>Responses of Intervenors to Interrogatories</b>	<b>Thursday, August 19, 2010</b>
<b>Submission of Final Arguments</b>	<b>Thursday, August 26, 2010</b>

c) Orders or directives with respect to such other matters as the Board sees fit.

**DATED** at the City of Fredericton, New Brunswick this 30<sup>th</sup> day of June, 2010.

**NEW BRUNSWICK SYSTEM OPERATOR**

**(Original signed by)**

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**Kevin C. Roherty**  
Secretary and General Counsel

1 **EXECUTIVE SUMMARY**  
2

3 New Brunswick System Operator (“NBSO”) is proposing changes to the Open  
4 Access Transmission Tariff (the “Tariff”) that will enable regular updates of the Real  
5 Power Loss factor to better reflect the system average transmission losses. The  
6 primary benefit of the proposed changes is to reduce the amount of energy settled  
7 in the redispatch market. These changes will improve the transparency and  
8 allocation of costs associated with transmission losses and result in a more efficient  
9 market.

10  
11 Since February of 2008 the 3.3% Real Power Loss factor, as established in the  
12 Tariff has resulted in an under estimation of the actual transmission losses  
13 approximately 80% of the time. As a consequence, a significant quantity of energy  
14 is being settled in the redispatch market as opposed to the bilateral market to  
15 compensate for unscheduled transmission losses. Compared to the treatment of  
16 losses in the bilateral market, the settlement of losses in the redispatch market is  
17 less transparent to parties involved in the transaction, and not as effective in  
18 allocating costs. In response, NBSO is proposing Tariff changes that would allow  
19 for regular updates of the Real Power Loss factor using a transparent formulaic  
20 approach.

21  
22 In general, the more responsive the Real Power Loss factor is to changes in actual  
23 transmission losses, the greater the reduction in the amount of energy being settled  
24 in the redispatch market. However, if updates to the Real Power Loss factor are too  
25 frequent and made on short notice it may result in lost market opportunities and  
26 increased administrative burden. In response to stakeholder feedback, the NBSO is  
27 proposing that the Tariff wording include conditions that Transmission Customers  
28 be given a minimum notice of three months prior to any change to the Real Power  
29 Loss factor and that it remain fixed for a period of at least three months. No  
30 changes are being proposed to the existing Tariff requirements that the Real Power  
31 Loss factor be based on system average losses and that the same factor be applied  
32 to all transactions in a postage stamp fashion.

1 It is proposed that the details on the frequency of updates, notice period, and  
2 calculation of the Real Power Loss factor be included in the Market Rules to provide  
3 greater flexibility to respond to evolving markets and opportunities for  
4 improvements.

5

6 The required Market Rule amendments associated with this Application are being  
7 developed under a parallel process. The current proposal would result in quarterly  
8 updates of the Real Power Loss factor, set a minimum notice period of three  
9 months, and calculate the loss factor based on the average system losses of the  
10 three month period immediately preceding the month that notice is published. The  
11 final Market Rule amendments will have to respect the outcome of this Application  
12 as the Tariff takes precedence over Market Rules.

13

14 Details of the proposed Tariff changes and Market Rule amendments are outlined in  
15 the Evidence at Tab 2. While the Market Rule amendment details are being  
16 provided, the NBSO is not seeking the Energy and Utilities Board's (the "Board")  
17 approval of them. Approval of Market Rule amendments are made by the NBSO  
18 Board, but, can be reviewed by the Board upon application by any person.

19

20 To ensure continuity and minimize confusion, NBSO suggests that the effective  
21 date of the proposed Tariff changes be set as the date that the associated Market  
22 Rule amendments come into effect. It is anticipated that Market Rules could be in  
23 effect within 45 days of a decision. As the proposal requires a three month notice  
24 period prior to any change in the Real Power Loss factor there is a need for an  
25 interim loss factor for the first few months. The proposed Market Rule amendments  
26 would set the interim loss factor at its current value of 3.3%.

# 1 REAL POWER LOSS FACTOR PROPOSED CHANGES

---

## 3 Purpose of the Real Power Loss Factor

4 In the New Brunswick Market, buyers and sellers are financially responsible for  
5 transmission losses on the system. In order to accomplish this, it is necessary to  
6 use a transmission loss factor to determine the amount of energy to include in the  
7 hourly energy schedules to make up for the transmission losses. For example,  
8 using the current Real Power Loss factor, of 3.3%, a buyer needing 1,000 MWh is  
9 required to have its seller schedule an injection of 1,033 MWh (1,000 MWh plus the  
10 losses of 33 MWh) into the system. The 1,000 MWh of energy used and 33 MWh of  
11 losses are transacted in the physical bilateral market with the buyer having the  
12 responsibility to pay the seller for them rather than paying the system operator.

13  
14 Ideally the transmission loss factor would be perfect at determining the actual  
15 losses. However, energy flows on the transmission system are constantly changing  
16 and, as a consequence, so are the losses. As a result, it is impossible to have a  
17 perfect transmission loss factor as the flows on the system cannot be perfectly  
18 forecasted.

19  
20 As the NBSO is required to balance the system any variance between actual losses  
21 and scheduled losses (which are determined by the loss factor) results in the  
22 redispatch of supply resources by NBSO. The cost or credit for this redispatch is  
23 added to the Residual Monthly Cost account ("RMC"), which is distributed to all  
24 Transmission Customers at the end of the month based on their respective pro-rata  
25 shares of the equivalent non-coincidental peak, in accordance with the Tariff and  
26 Market Rules.

27  
28 Using the example above, if the actual losses were 53 MWh, the 33 MWh of losses  
29 scheduled in the bilateral market would be 20 MWh short. To balance the system  
30 the NBSO would redispatch generation upwards. The cost of the redispatch would  
31 be added to the RMC account and charged to Transmission Customers though the

1 Residual Uplift mechanism. In this example, of the total 53 MWh of losses, 33 MWh  
2 are transacted in the bilateral market and 20 MWh in the redispatch market.

### 4 **Benefits of an Improved Real Power Loss Factor**

5 A transmission loss factor that results in an improved estimation of the actual losses  
6 will shift more of the losses from the redispatch market to the bilateral market which  
7 will:

- 9 • Result in more transparency of the financial impact of losses on  
10 Transmission Customers. Although the losses not covered in the bilateral  
11 market are picked up in the redispatch market through the RMC account, it is  
12 difficult for Transmission Customers to correlate the RMC account and  
13 Residual Uplift mechanism to the real cost of transmission losses. The RMC  
14 account is comprised of many items, only one of which includes transmission  
15 loss mismatches. Conversely, scheduled losses are readily quantified by  
16 individual Transmission Customers and those Transmission Customers know  
17 the costs.
- 18 • Improve the cost allocation of transmission losses by allocating the  
19 responsibility for losses to parties in proportion to their scheduled flows of  
20 energy. The bilateral market does a much better job at allocating  
21 transmission losses as it is based on scheduled energy flow which is more  
22 directly related to losses. By contrast, the financial impact of the losses  
23 settled in the redispatch market is currently allocated on the basis of non-  
24 coincidental peak, which is a measure of demand and only indirectly related  
25 to losses. For example, a Point-to-Point Customer with a firm transmission  
26 reservation and no scheduled energy would **not** be contributing to losses.  
27 However, since the allocation of the redispatch costs associated with the  
28 transmission loss mismatch is based on demand, that customer would be  
29 billed or credited for a portion of those redispatch costs.

- 1       • Reduce the unintended financial gains and losses of Market Participants that  
2 occur as a result of the settlement of transmission losses in the redispatch  
3 market. These costs can arise from a difference between the prices paid for  
4 losses by the Market Participant through the bilateral market, versus NBSO's  
5 settlement of losses through the redispatch market.

6  
7       **History**

8 In its March 31, 2003 decision, the Energy and Utilities Board's (the "Board")  
9 predecessor, the Public Utilities Board (the "PUB") approved the Tariff, the  
10 foundation of which exists today. The PUB ruled that a postage stamp approach to  
11 transmission losses was non-discriminatory and appropriate and that the use of a  
12 3.3% system average loss factor was fair and reasonable. The PUB noted in its  
13 Decision that the actual losses for 2000-2001 were 3.27% with a forecast of very  
14 little change going forward.

15  
16 As part of the Interrogatory process, the Applicant (NB Power) noted that the factor  
17 would be reviewed annually and revised as appropriate. Although the transmission  
18 loss factor in the Tariff document has not changed, NBSO reduced the factor from  
19 3.3% to 2.5% effective May 2006, as a result of decreased losses. Notice of this  
20 change was posted on the NBSO website. The factor was later increased to 4%  
21 effective February 2009, using the same process. The Board staff subsequently  
22 informed the NBSO that any change to the Real Power Loss factor would require an  
23 official application to amend the Tariff. In response, NBSO reduced the factor to the  
24 originally approved value of 3.3% on March 1, 2009.

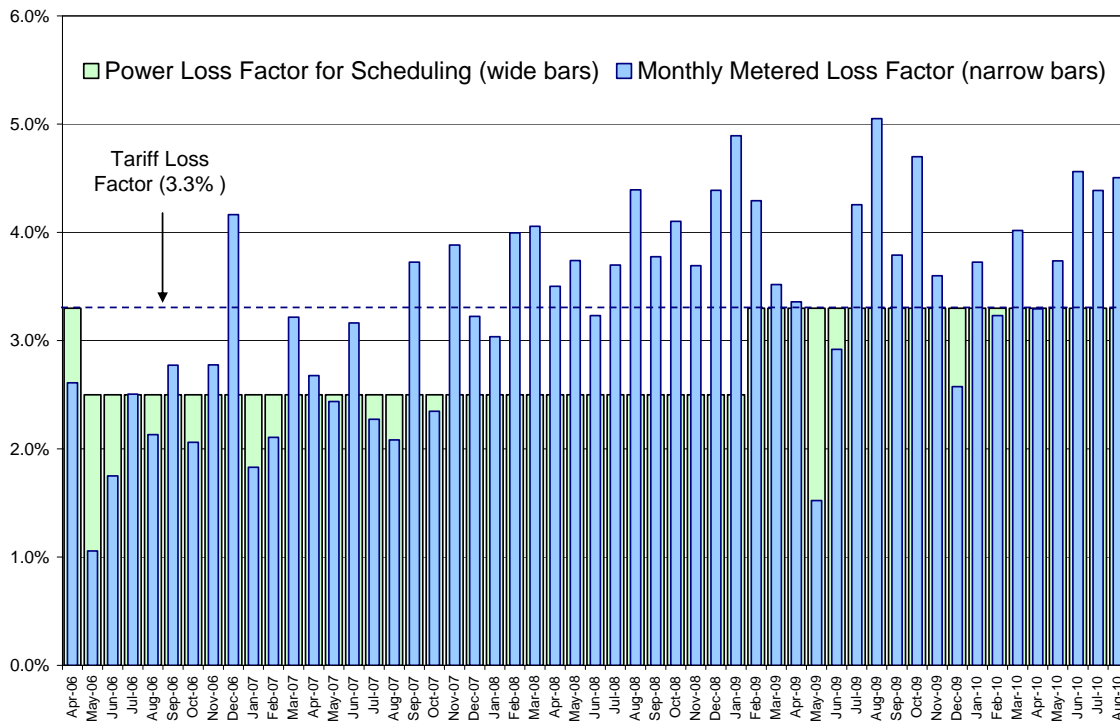
25  
26       **Issue**

27 An increase in transmission losses has resulted in a mismatch between the actual  
28 losses and the scheduled losses as determined by the Real Power Loss factor in  
29 many months. Figure 1 shows the Real Power Loss factor, the loss factor used by  
30 Transmission Customers for scheduling and the metered loss factor over the period  
31 of April 2006 to August 2010. The metered loss factor is equal to the actual metered  
32 losses divided by the total scheduled energy amounts. It represents the ideal loss

1 factor and is used as a benchmark to make comparisons against. Since February of  
2 2008, the 3.3% Real Power Loss factor has been less than the monthly metered  
3 loss factor 80% of the time. The difference has been as high as 1.75%

4

**Figure 1**  
**Power Loss Factor for Scheduling vs. Metered Loss Factor**



5 As a result of the differences, a significant quantity of energy that is required to  
6 compensate for transmission losses is being settled in the redispatch market as  
7 opposed to the bilateral market. As previously discussed the redispatch market is  
8 not as efficient as the bilateral market in the transparency and allocation of the costs  
9 associated with transmission losses.

10

11 There are many dynamic factors that affect transmission losses including grid  
12 configuration, location and output of generators, location and demand of loads,  
13 import injections and location, and export withdrawals and location. The specific  
14 dispatch of supply sources will be affected by volatile fossil fuel prices, generation  
15 plant outages and retirements, possible greenhouse gas regulatory requirements,

1 and changing market conditions. Load patterns will depend on the state of  
2 electricity intensive industry, regional growth and adjacent market conditions. All of  
3 these factors cause transmission losses to be highly variable and difficult to predict.

4  
5 The general rise in transmission losses is due to an increase in the North to South  
6 flow of energy. The displacement of Point Lepreau generation with imports from  
7 Québec, wheeling of energy from Québec to New England through New Brunswick,  
8 and loss of load in the North are examples of factors contributing to higher flows  
9 from North to South. Generally, higher use and greater distance between injections  
10 and withdrawals will increase losses.

11  
12 The existing approach of using a system-wide Real Power Loss factor, as approved  
13 by the PUB in 2003, is non-discriminatory, treats all Transmission Customers  
14 equally, and avoids the complexity of a path specific approach.

15  
16 Given the recent variability in the metered transmission loss factor (Figure 1) and an  
17 expectation of continued variability, a more dynamic approach to updating the Real  
18 Power Loss factor would be beneficial.

19  
20 **Proposal**

21 The current approach whereby the Real Power Loss factor is fixed in the Tariff does  
22 not lend itself to responsive updates as a change to the factor requires a Tariff  
23 amendment that is subject to a rigorous regulatory process.

24  
25 The NBSO is proposing that the Real Power Loss factor be updated at fixed  
26 intervals using a transparent formulaic approach. In developing the approach the  
27 details to consider include the, length of notice period, frequency of updates,  
28 calculation methodology, and split between what is included in the Tariff and the  
29 Market Rules. These details are discussed below.

1 There are both administrative and market reasons for providing a notice period prior  
2 to any change in the Real Power Loss factor. Participation in the New England  
3 Forward Capacity Market ("FCM") has been identified as the governing reason for  
4 the length of the notice period. Participants in the FCM are required to make an  
5 obligation to deliver a set level of capacity 2 to 3 years in the future. They must  
6 have both the generation and an adequate transmission path to deliver the capacity.  
7 Changes to the Real Power Loss factor has an impact on the capacity that  
8 participants can deliver. For example, a 100 MW generator can deliver 96.8 MW  
9 with a loss factor of 3.3% but only 95.2 MW with a loss factor of 5%. To avoid  
10 penalties for non-delivery, a generator could be conservative and only sell 90 MW of  
11 capacity knowing that the loss factor would rarely exceed 10%, but, they would  
12 lose a portion of the market. The FCM market does, however, include  
13 mechanisms where the participant can assign their obligation to another party. To  
14 take advantage of these mechanisms the participant requires three months advance  
15 knowledge that they will be short on their capacity obligation. As the NBSO does  
16 not wish to reduce market opportunities, it is proposed that a minimum notice period  
17 of three months be given, prior to any change in the Real Power Loss factor.

18

19 The frequency of loss factor updates is largely an administrative issue as more  
20 frequent adjustments will cause increased burden for Market Participant's that are  
21 scheduling energy or committing capacity. Based on feedback from Market  
22 Participants, updating the factor on a monthly basis would be burdensome. On the  
23 other hand, updating on a semi annual basis does result in a significant  
24 improvement over the status quo where the Real Power Loss factor is fixed at 3.3%.  
25 Consequently, the NBSO is proposing that the factor remain fixed for a minimum  
26 period of three months. If the actual metered loss factors stabilize over time, it may  
27 be possible to fix the factor for longer periods and still meet the primary objective.

28

29 The NBSO is proposing that the loss factor continue to be based on system  
30 average losses and applied in a postage stamp fashion. The average loss factor is  
31 simply the metered historic losses divided by the scheduled deliveries over the

1 same time period. The only remaining consideration is the period over which the  
2 average is taken. Based on an analysis of historic data and respecting the  
3 frequency and notice constraints discussed above, the period that gave the lowest  
4 average error (metered vs. calculated) was the three months immediately prior to  
5 the month that the notice is issued.

6

7 Applying the proposed notice and frequency constraints appear to increase the  
8 average error when compared to the use of more frequent updates and shorter  
9 notice periods. While the application of these proposed constraints is counter to the  
10 objective of reducing the amounts settled in the redispatch market, it is considered  
11 to be an acceptable trade off between the objective and the impacts on Market  
12 Participants.

13

14 For greater clarity the following example illustrates how the Real Power Loss factor  
15 would be set for a specific period. The loss factor for January 1, 2011 to March 31,  
16 2011 would be published in September 2010 and equal to the average system  
17 losses over the period of June to August 2010.

18

19 Using the proposed methodology, the monthly Real Power Loss factors and actual  
20 metered loss factors are shown in Figure 2. As compared to Figure 1, there is a  
21 distinct improvement in the match between these factors. The result should be a  
22 better match between the scheduled losses and the actual metered losses.

23

24

25

26

27

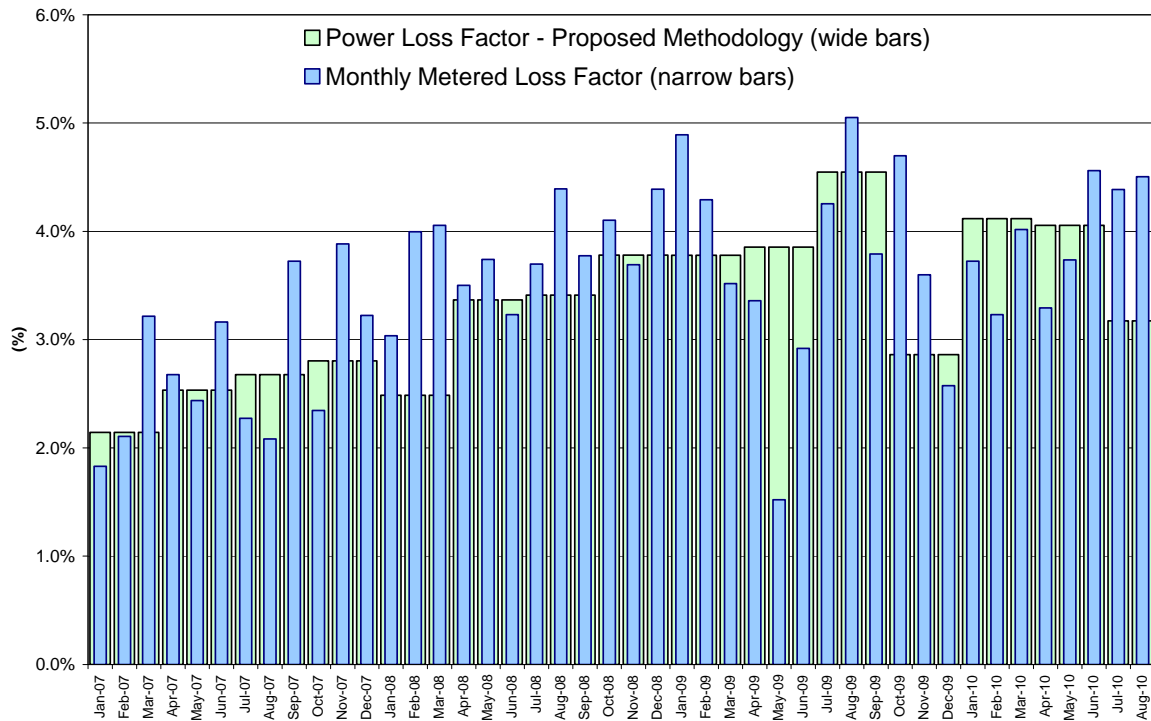
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29

30

1  
2

**Figure 2**  
**Proposed Methodology vs. Metered Losses**



3 With respect to the division between the Tariff and Market Rules, it is proposed that  
4 the Tariff continue to include the requirements that the factor be based on system  
5 average losses, but, that it be modified to include constraints on the frequency of  
6 updates, length of notice period and allow for the details of the calculation  
7 methodology to be set in the Market Rules. As the Tariff takes precedence over the  
8 Market Rules, the methodology for calculating the loss factor in the Market Rules  
9 must respect the outcome of this Application.

10

11 The reason for including the detailed methodology in the Market Rules as opposed  
12 to the Tariff is to allow for a greater level of flexibility in making amendments to the,  
13 frequency of updates, length of notice period and the period over which the system  
14 average loss is determined. Amendments may be required to respond to evolving  
15 markets and opportunities for improvements. There continues to be regulatory  
16 oversight, as any party can request that the Energy and Utilities Board undertake a  
17 review of a Market Rule amendment.

1 The proposed constraints on the notice period, frequency of update calculation of  
2 the average system loss and split between the Tariff and Market Rules were  
3 reviewed and unanimously accepted by the Market Advisory Committee (the  
4 “MAC”) at the October 19, 2010 meeting.

5  
6 Although not a member of the MAC, Hydro-Québec Production is also in favour of  
7 the proposal. They are a participant in the FCM market and as a result are directly  
8 affected.

9  
10 Proposed Tariff Amendments

11  
12 The specific proposed changes to the Tariff are as follows, with the text that is to be  
13 deleted struck out, and added words underlined.

14  
15 Section 15.7 (Real Power Losses)

16 *Real Power Losses are associated with all transmission service. The*  
17 *Transmission Provider is not obligated to provide Real Power Losses. The*  
18 *Transmission Customer is responsible for replacing losses associated with*  
19 *all transmission service as calculated by the Transmission Provider. The*  
20 *applicable Real Power Loss factors are based on system average losses and*  
21 *will be calculated in accordance with the Transmission Provider’s Market*  
22 *Rules. Transmission Customers shall be given a minimum of three months*  
23 *notice of any change to the Real Power Loss Factor and the Real Power*  
24 *Loss Factor shall remain fixed for a minimum period of three months. The*  
25 *~~system average loss factor is 3.30%.~~*

26  
27 Section 28.5 (Real Power Losses)

28 *Real Power Losses are associated with all transmission service. The*  
29 *Transmission Provider is not obligated to provide Real Power Losses. The*  
30 *Network Customer is responsible for replacing losses associated with all*  
31 *transmission service as calculated by the Transmission Provider. The*

1 applicable Real Power Loss factors are based on system average losses and  
2 will be calculated in accordance with the Transmission Provider's Market  
3 Rules. Transmission Customers shall be given a minimum of three months  
4 notice of any change to the Real Power Loss Factor and the Real Power  
5 Loss Factor shall remain fixed for a minimum period of three months. The  
6 system average loss factor is 3.30%.  
7

#### 8 Proposed Market Rule Amendments

9 Should the proposed revisions to the Tariff be approved by the Board, the details on  
10 notice period, frequency of updates and methodology for calculating the Real Power  
11 Loss factor including the formula will be incorporated into the Market Rules  
12 consistent with the Tariff.

13  
14 The following Market Rule amendments will be proposed through the formal Market  
15 Rule amendment process.

#### 16 17 New Section 6.5C Real Power Loss Factor

18  
19 6.5C.1 The Real Power Loss factor shall be fixed for a period of three  
20 months and begin on the first hour of January 1, April 1, July 1 and October  
21 1.  
22

23 6.5C.2 The Real Power Loss factor and the aggregate data used in its  
24 determination shall be Published at least 3 months prior to the Real Power  
25 Loss factor coming into effect.  
26

27 6.5C.3 The Real Power Loss factor shall be determined as the sum of the  
28 metered losses ÷ sum of Final Hour Balanced Schedule withdrawals over the  
29 three calendar month period immediately preceding the month that the Real  
30 Power Loss factor is Published.

1 6.5C.4 The metered losses referred to in section 6.5C.3 shall be determined  
2 as the difference between the sum of all of the actual metered or imputed  
3 injections into the SO-controlled Grid and the sum of all of the actual metered  
4 or imputed withdrawals from the SO-controlled Grid over the same time  
5 period.

6  
7 6.5C.5 Any time that the Real Power Loss factor cannot be set as described  
8 in sections 6.5C.1 to 6.5C.4 the Real Power Loss factor shall be 0.033.

9  
10 Edits to Existing Sections

11  
12 6.6.3 A Market Participant wishing to have the SO schedule an energy  
13 transaction on a Dispatch Day shall, except as otherwise noted in section  
14 6.7.3(c), by 11:00 on the corresponding Day Ahead, submit to the SO a  
15 Provisional Balanced Schedule comprising:

16 a) a balanced hourly schedule of energy flows utilizing firm Point-to-  
17 Point Service, specifying injection and withdrawal Delivery Points,  
18 including those at Interconnections, and the quantities of energy to be  
19 injected and withdrawn at each, to take account of Transmission losses in  
20 accordance with the ~~Market Rules Transmission Tariff~~;

21 b) a balanced hourly schedule of energy flows utilizing Network  
22 Integration Service, specifying injection and withdrawal Delivery Points or  
23 Virtual Delivery Points, including those at Interconnections where not  
24 prohibited by the Transmission Tariff, and the quantities of energy to be  
25 injected at each, taking account of Transmission losses in accordance  
26 with the ~~Market Rules Transmission Tariff~~; and

27  
28 7.6.12 The SO shall determine the schedule rounding error for each hour in  
29 accordance with the following formula:

30  $Q(\text{injection}) - [Q(\text{withdrawal}) * (1 + \text{Real Power Loss factor } \text{transmission}$   
31  $\text{loss factor})]$ , rounded to the nearest kWh

1 **Quantitative Impacts**

2 In order to assess the potential impact of the amount of energy settled in the  
3 bilateral vs. redispatch market, an hourly analysis was undertaken using actual data  
4 over the two year period of April 1, 2008 to March 31, 2010. The analysis includes  
5 an estimate of the dollar value of the energy settled in the redispatch market as a  
6 result of the difference between the actual metered losses and losses as  
7 determined by the Real Power Loss factor. The Final Hourly Marginal Cost was  
8 used as a proxy for redispatch costs. The results of the analysis are illustrated in  
9 Table 1 below.

10  
11 **Table 1**  
12 **Redispatch vs. Bilateral Market Impact**

	<b>At Current 3.3% Loss Factor</b>	<b>Using Proposed Loss Factor</b>	<b>Difference</b>	<b>%</b>
Bilateral Market (Scheduled MWh Injections)	36,901,551	37,047,643	146,092	0.4%
Redispatch Market (MWh)	170,088	23,996	-146,092	-85.9%
Estimate of Redispatch Costs	\$7,904,409	\$2,266,235	\$-5,638,174	-71.3%

13 Using the proposed method, a total of 146,092 MWh is moved from the redispatch  
14 market to the bilateral market. This represents an 86% reduction in the energy  
15 settled in the redispatch market. The estimated Redispatch Costs which flow into  
16 the Residual Monthly Cost account are reduced by over \$5.6 million. The  
17 corresponding increase in the amount of energy transacted in the bilateral market  
18 also has an associated cost but the NBSO has no means by which to estimate its  
19 value.

20  
21 If the losses as determined by the application of the Real Power Loss factor were  
22 exactly equal to the metered transmission losses in every hour there would be no  
23 redispatch as a result of losses. While it is impossible to achieve this ideal situation,

1 the proposed methodology for revising the Real Power Loss factor is an  
2 improvement over the current practice.

3  
4 The implementation of the proposed solution should reduce the net RMC dollars as  
5 the transmission losses settled in the redispatch market are a significant contributor  
6 to the dollars in the Residual Monthly Cost account. Unlike generator and load  
7 imbalance there is no offsetting flow of dollars within the Residual Monthly Cost  
8 calculation to compensate for redispatch caused by transmission loss mismatch.  
9 For example, in the case of load imbalance, if generation is dispatched up because  
10 the load forecast was low, the NBSO charges the load at the Final Hourly Marginal  
11 Cost and pays the Generator at their bid price and to some extent the dollars  
12 cancel. There are no such offsets within the Residual Monthly Cost calculation with  
13 respect to the transmission loss mismatch.

#### 14 15 **Financial Impact on Market Participants**

16 As transmission losses are either dealt with in the bilateral market or redispatch  
17 market, there is no escaping payment. The bottom line financial impact on Market  
18 Participants will vary depending on whether the Real Power Loss factor is too high  
19 or too low and the relationship between the NBSO dispatch prices and bilateral  
20 contract prices and the imperfect allocation of the RMC account. The NBSO does  
21 not have bilateral contract pricing information and is not in a position to analyze the  
22 financial impact on a Market Participant by Market Participant basis. However, the  
23 following table illustrates some general observations on the financial impact for  
24 Generators and Load Customers assuming a perfect allocation of redispatch costs.

25  
26 For generators, it is assumed that they sell in the bilateral market at a profit and  
27 break even in the redispatch market. As generators do not know if they will be  
28 dispatched up or down they are motivated to submit bid prices in the redispatch  
29 market that reflect marginal costs in order to remain whole.

1  
2

**Table 2**  
**Financial Impact**

	Case A	Case B	Case C	Case D
Transmission Loss Factor	Low	Low	High	High
Prices	Low Redispatch High Bilateral	High Redispatch Low Bilateral	Low Redispatch High Bilateral	High Redispatch Low Bilateral
Schedules	Low	Low	High	High
NBSO Action	Dispatch Up	Dispatch Up	Dispatch Down	Dispatch Down
Load – Financial Impact	<u>Positive</u> Loads are buying less high priced bilateral energy and paying for low priced redispatch energy to make up the shortfall.	<u>Negative</u> Loads are buying less low priced bilateral energy and paying for high priced redispatch energy to make up the shortfall.	<u>Negative</u> Loads are buying more high priced bilateral energy and being reimbursed for low priced redispatch surplus.	<u>Positive</u> Loads are buying more low priced bilateral energy and being reimbursed for high priced redispatch surplus.
Generators	<u>Negative</u> Generators are selling less energy in the bilateral market for a profit.	<u>Negative</u> Generators are selling less energy in the bilateral market for a profit.	<u>Positive</u> Generators are selling more energy in the bilateral market for a profit.	<u>Positive</u> Generators are selling more energy in the bilateral market for a profit.

3 **Transition**

4 As the overall proposal for making revisions to the method of updating the Real  
5 Power Loss factor involves both changes to the Tariff and Market Rules there is a  
6 requirement for coordination between the two processes. There is also a need to  
7 have a mechanism in place at all times to set the factor as it is used on a daily basis  
8 for scheduling purposes.

9

10 To ensure continuity and minimize market confusion, it is proposed that the decision  
11 for this Application be effective on the date upon which the associated Market Rules  
12 come into effect. It is anticipated that Market Rule amendments could be in effect  
13 within 45 days of a decision on this Application. The final Market Rule amendments  
14 will have to respect the outcome of this Application as the Tariff takes precedence  
15 over Market Rules.

1 If the Tariff decision were to come into effect prior to the Market Rule changes there  
2 is the potential that there would be no mechanism to set the loss factor. A possible  
3 solution would be to include text in the Tariff stating that the Real Power Loss factor  
4 be set at 3.3% until such time that the associated Market Rule amendments are in  
5 effect.

6

7 It is also possible that the Tariff decision could come into effect after the effective  
8 date of the associated Market Rule amendments as the Tariff takes precedence  
9 over the Market Rules. Until such time that the Tariff changes come into effect, the  
10 factor would be set in accordance to the provisions of the Tariff and not the Market  
11 Rules. This could cause some confusion with Market Participants as there would  
12 be a discrepancy between the Tariff and Market Rules. The outcome of the hearing  
13 may also cause further unanticipated changes to the Market Rules requiring the  
14 NBSO to redo the amendments.

15

16 Regardless of the approach that is taken with respect to the timing of the effective  
17 dates of both the Tariff and Market Rule changes, there is a requirement for an  
18 interim Real Power Loss factor. The fact that a three month notice period is being  
19 proposed prior to any change of the factor means that for the first few months an  
20 interim factor has to be set. Section 6.5C.5 of the proposed Market Rule  
21 amendments deals with this issue and states that the Real Power Loss factor be set  
22 at 3.3% if the factor cannot be set in accordance with the proposed methodology.

23

24 **Conclusion**

25 In summary, NBSO is proposing Tariff changes that will enable regular updates of  
26 the Real Power Loss factor to better reflect the actual system average transmission  
27 losses. The proposed change received unanimous support from the Market  
28 Advisory Committee. The change will improve the transparency and allocation of  
29 costs associated with transmission losses and result in a more efficient market. The  
30 Tariff will set out constraints on the notice period, frequency of updates while the

- 1 Market Rules will set the notice period, frequency of updates and period over which
- 2 to calculate the loss factor.
- 3
- 4 NBSO respectively requests that the Board approve the Real Power Loss factor
- 5 changes to the Tariff as proposed in this Application.