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May 2nd, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Veridian Connections Inc., Motion to Review
Board File No. EB-2012-0201

In accordance with Procedural Order No. 1 in the above noted matter, please find attached the written motion of Veridian Connections Inc.

Yours truly,

Original signed by

George Armstrong
Vice President, Corporate Services

EB-2012-0201

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Veridian Connections Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.;

AND IN THE MATTER OF the Board's Decision dated March 22, 2012 (File Number EB-2011-0199).

MOTION

1. In accordance with Procedural Order No. 1 in this matter, this is the written motion of Veridian Connections Inc. ("Veridian"). This motion has been divided into three parts: (i) background information; (ii) the threshold question; and (iii) the merits of the motion.

(i) Background Information:

2. Some of the background information contained in this section is repetitive of the information contained in Veridian's Notice of Motion, but has been provided herein to assist the Board.

The Bluewater Power Decision and Order:

3. As set out in the Notice of Motion, the Board has treated Veridian differently from Bluewater Power ("Bluewater").

4. On March 22, 2012, the same date that the Decision and Order in this proceeding was issued (the "Decision") [set out at Appendix "A"], the Board issued a Decision and Order in the Bluewater Power ("Bluewater") proceeding (EB-2011-0153) (the "Bluewater Decision") [set out at Appendix "B"].

5. In the Bluewater Decision, the same panel of the Board as in the Veridian proceeding approved Bluewater's LRAM recovery of the effect in 2010 of its programs implemented in 2006-2010.

6. Bluewater’s distribution rates were established on a forward test year, cost of service basis in 2009.

7. The basis for the Bluewater Decision was that Bluewater's 2009 Settlement Agreement specifically provided for the exclusion of CDM impacts in its load forecast. The relevant portion of Bluewater's Settlement Agreement is:

   “For the sake of clarity, the revised forecast does not reflect in any way specific electricity conservation programs.”[1]

8. Veridian's 2010 settlement agreement in EB-2009-0140 (the "Settlement Agreement") also provided for the exclusion of CDM impacts in its load forecast. The relevant portion of Veridian's Settlement Agreement was:

   3 b. *Is the impact of CDM initiatives suitably reflected in the load forecast?*
   Complete Settlement: Veridian has not included any CDM program impacts in the 2010 load forecast as details regarding Ontario Power Authority programs in the test year were not available at the time that the load forecast was prepared. For the purpose of obtaining complete settlement of all issues, the Parties agree that this treatment is appropriate.

9. The LRAM claims of both Veridian and Bluewater included the persisting impacts of CDM programs in a cost of service test year.

[1] Page 14 of the Bluewater Decision.

10. The <u>only</u> difference between Veridian's and Bluewater's LRAM claims was that Veridian provided an estimate of implicit CDM impacts in its load forecast, and proposed to reduce its LRAM claim accordingly.

11. In Veridian's Reply Submission dated January 30, 2012 in EB-2011-0199 [set out at Appendix "C"], it explained that in preparing a response to Board Staff interrogatory #14 [set out at Appendix "D"], it realized that its load forecast likely included some implicit CDM impacts related to programs delivered in prior years. The Decision referred to that oversight as a "contradiction" of the Settlement Agreement, which resulted in the Board effectively ignoring section 3b of the Settlement Agreement (section 3b is set out above).

12. Clearly, the intentions of the parties in both the Veridian and Bluewater Settlement Agreements were to depart from the Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "Guidelines" or "2008 CDM Guidelines") issued on March 28, 2008 by excluding CDM impacts in the load forecasts. The Board respected that intention in Bluewater's case, but did not in Veridian's case.

<u>The Enersource Decision and Order:</u>

13. On April 19, 2012 the Board issued a Decision and Order in the Enersource Hydro Mississauga Inc. ("Enersource") proceeding (EB-2011-0100) (the "Enersource Decision") [set out at Appendix "E"].

14. In the Enersource Decision, the Board approved the recovery of Enersource's lost revenues for 2010, which included the persistence of CDM savings from programs that were implemented prior to Enersource's 2008 cost of service rebasing.

15. The relevant portion of the Enersource Decision is:

> *"The Board will approve Enersource's revised LRAM claim of $860,339, representing lost revenues arising from the persistence of 2005-2009 CDM programs in 2010 and lost revenues from 2010 CDM programs in 2010. In*

> *general, the Board is of the view that LRAM is accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.* ***However, as set out in the Settlement Agreement and the transcript from the oral hearing in EB-2007-0706, in which the Settlement Agreement was accepted by the Board, it is apparent that the intent was to remove the CDM effects from the load forecast and defer consideration of those CDM effects to a future LRAM proceeding. As such, the Board is of the view that it is appropriate to deviate from the 2008 CDM Guideline and approve the LRAM recovery sought by Enersource in this application.*** *The Board approves a one year disposition period, May 1, 2012 to April 30, 2013."* [emphasis added]

16. Just as in the Bluewater Decision, the Board departed from the 2008 CDM Guideline and approved Enersource's LRAM claim based on the apparent intention to remove the CDM effects from the load forecast and defer consideration of those CDM effects to a future LRAM proceeding.

17. Enersource, Bluewater and Veridian all intended to remove the CDM effects from their load forecasts to defer for future recovery. Nevertheless, the Board accepted Bluewater's and Enersource's claims but denied Veridian's.

(ii) The Threshold Question:

18. Section 44.01 of the Board's *Rules of Practice and Procedure* (the "Rules") requires that a motion to review a decision must set out the grounds for the motion that raise a question as to the correctness of the decision. The list of grounds provided in the Rules is not exhaustive, as evidenced by the words, "which grounds may include".

19. As such, a moving party is not limited by the grounds set out in Section 44.01 of the Rules, and may bring a motion on grounds other than those listed.

20. The ground for Veridian's motion is regulatory inconsistency, which is synonymous with regulatory arbitrariness.

21. The Supreme Court of Canada has recognized the importance of the objective of consistency in decision making, as illustrated by the following quote:[2]

> *"While the analysis of the standard of review applicable in the case at bar has made clear the significance of the decision-making autonomy of an administrative tribunal, the requirement of consistency is also an important objective. As our legal system abhors whatever is arbitrary, it must be based on a degree of consistency, equality and predictability in the application of the law. Professor MacLauchlan notes that administrative law is no exception to the rule in this regard:*
>
> *'Consistency is a desirable feature in administrative decision-making. It enables regulated parties to plan their affairs in an atmosphere of stability and predictability. It impresses upon officials the importance of objectivity and acts to prevent arbitrary or irrational decisions. It fosters public confidence in the integrity of the regulatory process. It exemplifies "common sense and good administration"'.*

22. The Board has also recognized the value of consistency in decision making:

> *"...the Board recognizes the value of consistency in decision-making. Departures from established decisions should only be made on the basis of reasoned principle. However, panels of the Board are not and cannot be thought to be bound to the decisions of proceeding panels. Each panel must make its decision on the basis of the facts before it and the relevant policies and principles affecting the decision."* [3]

23. Veridian submits that consistency in decision-making is important to the integrity of the regulatory process and it should be abandoned only in the clearest of circumstances, that is, when circumstances of one case are clearly distinguishable from the other.

24. With the exception of the treatment of implicit CDM impacts, the circumstances in Veridian's proceeding were not distinguishable from those in the Bluewater and Enersource proceedings. Although Veridian identified some implicit CDM impacts

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[2] L'Heureux-Dube J. in *Domtar Inc. v. Quebec (Commission d'appel en matiere del lesions professionelles), 1993 CanLII 106 (S.C.C.)* at page19.

[3] EB-2011-0256 Decision at page 5.

related to programs delivered in prior years (and adjusted its proposed LRAM claim accordingly), the intention to remove CDM impacts from the load forecast for future recovery in the settlement agreement should receive the same Board treatment for Veridian, Enersource and Bluewater.

25. From a common sense perspective, it makes no sense that the LRAM claim of Veridian was denied, while the claims of Bluewater and Enersource were accepted. Further, the Board did not depart from the Bluewater and Enersource Decisions "on the basis of reasoned principle", as described in the Board's decision set out in paragraph #22 above.

26. Because of this disparate treatment by the Board, as well as the importance of the objective of consistency in decision making described by the Supreme Court of Canada, Veridian submits that *in this circumstance* the ground of regulatory inconsistency satisfies the threshold for a motion to review.

(iii) The Merits of the Motion:

27. The basis for the Board's approval of Bluewater's and Enersource's LRAM claims was their intention to remove the CDM effects from the load forecast and defer consideration of those CDM effects to a future LRAM proceeding, as suggested by their settlement agreements.

28. That very same intention was expressed in Veridian's Settlement Agreement (see paragraph #8 above).

29. Like Bluewater and Enersource, Veridian’s cost of service test year load forecast was prepared using a regression model, with no adjustments for CDM impacts related to CDM program activity in the test year.

30. In recognition that the presence of prior period CDM effects within the historic dataset used in the regression model likely resulted in some implicit CDM impacts in its test year forecast, Veridian proposed to reduce its LRAM claim by $85,814 from $1,389,688 to $1,303,874 to account for implicit CDM impacts related to programs delivered in prior years.

31. Veridian's methodology for calculating implicit CDM impacts related to programs delivered in prior years was provided during the evidentiary portion of the proceeding in response to Board Staff interrogatory #14 [set out at Appendix "C"].

32. Instead of following the logic it applied in the Bluewater and Enersource proceedings with the adjusted LRAM amount provided by Veridian, the Board treated the implicit CDM impacts as a "contradiction" to the Settlement Agreement that, from the Board's perspective, effectively voided section 3b of the settlement agreement (i.e. the intention to remove CDM effects from the load forecast and defer for future recovery).

33. This "all or nothing" approach taken by the Board was unreasonable. Based on the Board's logic, if Veridian had identified $1 of implicit CDM impacts in its load forecast, Veridian would have been denied its entire LRAM claim for 2010 revenue impacts of CDM program activities. Clearly, such an outcome would be absurd.

34. To summarize, the Board's decision in this regard should be reviewed and varied for the following reasons:
    a. Veridian's 2010 Settlement Agreement expressly stated the intentions of the parties that CDM effects were excluded from the test year forecast because details regarding Ontario Power Authority programs in the test year were not available at the time that the load forecast was prepared;
    b. the Board accepted the Settlement Agreement as part of its final decision in EB-2009-0140;
    c. During Veridian's IRM proceeding EB-2011-0199, Veridian determined that its load forecast likely included implicit CDM effects;

d. Veridian brought the issue to the Board's attention voluntarily;

e. In order to maintain the intention of the Settlement Agreement to remove the CDM effects from the load forecasts to defer for future recovery (section 3b of the Settlement Agreement), Veridian proposed a reduced LRAM claim that removed implicit CDM impacts from its load forecast;

f. Veridian proposed this adjustment during the evidentiary phase of the proceeding, so the Board could have tested Veridian's adjustment had it wanted to through further interrogatories, a technical conference or an oral hearing;

g. no further inquiries were made about Veridian's proposed adjustment;

h. rather than accept Veridian's well intentioned LRAM adjustment, the Board treated Veridian's oversight as a "contradiction" to the settlement agreement;

i. based on that "contradiction" the Board disregarded the intention of the parties to remove the CDM effects from the load forecasts to defer for future recovery, despite the fact that the Settlement Agreement was accepted as part of a final Board decision in EB-2009-0140;

j. the Board denied Veridian's <u>entire</u> LRAM claim for 2010 revenue impacts of CDM program activities (i.e. an all-or-nothing approach) rather than consider Veridian's claim on an adjusted basis; and

k. the same panel of the Board accepted the intentions of Bluewater and Enersource to remove the CDM effects from the load forecasts to defer for future recovery.

35. For all of these reasons, Veridian requests that the Board's March 22, 2012 Decision and Order in the EB-2011-0199 proceeding be reviewed and varied as follows:

a. that Veridian be permitted to recover an LRAM amount of $480,913 representing 2010 revenue impacts of CDM program activities.[4]

[4] Veridian's total adjusted LRAM claim was for $1,303,874 (Table 11 of Veridian's Reply Submission). The Board approved the recovery of $822,961for the 2007-2009 legacy programs (p.15 of the Decision). The difference (or unapproved amount) is $480,913.

All of which is respectfully submitted.

May 2, 2012

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Veridian Connections Inc.
By its Counsel: Andrew Taylor

Appendix A

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2011-0199

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Veridian Connections Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

BEFORE: Karen Taylor
Presiding Member

Paula Conboy
Member

DECISION AND ORDER

Introduction

Veridian Connections Inc. ("Veridian"), a licensed distributor of electricity providing service to consumers within its two licensed service areas: Veridian – Main and Veridian – Gravenhurst. Veridian filed an application with the Ontario Energy Board (the "Board") on October 14, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Veridian charges for electricity distribution, to be effective May 1, 2012.

The application for both Veridian – Main and Veridian – Gravenhurst service areas was assigned Board file number EB-2011-0199. The Board has combined its findings in this Decision and Order where applicable. In situations where differentiations need to be made between Veridian – Main and Veridian – Gravenhurst, they are separately addressed in this Decision and Order.

By letter dated October 19, 2011, the Board accepted Veridian's rationale for not proposing disposition of Account 1562 - Deferred Payments in Lieu of Taxes ("PILs") in its 2012 IRM application. The Board noted its expectation that Veridian would address the disposition of Account 1562 in a stand-alone application to be filed no later than April 1, 2012.

Veridian is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, establishes a three year plan term for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed. As part of the plan, Veridian is one of the electricity distributors that will have its rates adjusted for 2012 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports contain the relevant guidelines for 2012 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 22, 2011, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

Notice of Veridian's rate application was given through newspaper publication in Veridian's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors would be eligible for cost awards with respect to Veridian's proposed lost revenue adjustment mechanism ("LRAM") recovery and proposed revenue-to-cost ratio adjustments for Veridian – Gravenhurst. The Vulnerable Energy Consumers

Coalition ("VECC") applied and was granted intervenor status in this proceeding. The Board granted VECC eligibility for cost awards in regards to Veridian's request for LRAM recovery and any revenue-to-cost ratio matters that go beyond the implementation of previous Board decisions. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Revenue-to-Cost Ratio Adjustments;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Review and Disposition of Account 1521: Special Purpose Charge; and
- Review and Disposition of Lost Revenue Adjustment Mechanism.

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator, less a productivity factor (X-factor) of 0.72% and a stretch factor.

On March 13, 2012, the Board announced a price escalator of 2.0% for those distributors under IRM that have a rate year commencing May 1, 2012.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. . In its letter to Licensed Electricity Distributors dated December 1, 2011 the Board assigned Veridian to efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes that are not eligible for Rural or Remote Electricity Rate Protection.

The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The draft Tariff of Rates and Charges flowing from this Decision and Order will reflect the new RRRP charge.

Revenue-to-Cost Ratio Adjustments

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges (the "Target Ranges") for Ontario electricity distributors in its report *Application of Cost Allocation for Electricity Distributors* dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy* dated March 31, 2011.

Veridian proposed to increase the revenue-to-cost ratio for the Residential Suburban Year Round and Sentinel Lighting rate classes in the Gravenhurst service area to a value closer to the lower boundary of the Board approved target ranges.

Veridian proposed that the additional revenues from these adjustments be used to reduce the revenue-to-cost ratio for the General Service Less Than 50 kW and General Service 50 to 4,999 kW rate classes noting that the ratio for these classes is within the Board Target Ranges but that the ratio for those rate classes is currently the highest.

The table below outlines the proposed revenue-to-cost ratios:

Rate Class	Current 2011 Ratio	Proposed 2012 Ratio	Target Range
Residential Urban Year-Round	108.7	108.7	85 – 115
Residential Suburban Year Round	69.5	77.2	85 – 115
Residential Suburban Seasonal	87.1	87.1	85 – 115
General Service Less Than 50 kW	133.5	121.2	80 – 120
General Service 50 to 4,999 kW	163.2	159.4	80 – 180
Sentinel Lighting	43.3	56.6	70 – 120
Street Lighting	83.3	83.3	70 – 120

In its submission, Board staff noted that the Settlement Agreement approved by the Board in Veridian's 2010 cost of service application (EB-2009-0140) did not provide any direction on the revenue-to-cost ratio adjustments during the IRM plan term. However, Board staff also noted that Veridian proposed further adjustments to be made over this period in its 2010 rate application. Board staff submitted that Veridian's proposal in this proceeding is consistent with the Board's approval in Veridian's 2011 IRM application (EB-2010-0117) and that the changes proposed by Veridian are reasonable and should be accepted by the Board.

In its submission, VECC noted that Veridian proposed in its 2010 cost of service application to adjust the existing revenue-to-cost ratios to the boundaries of the Board target ranges over a four-year period. VECC also noted that a full settlement was reached in that proceeding and that the settlement was silent on proposed changes in 2011 and beyond. VECC submitted that the revenue-to-cost ratio adjustments proposed for 2012 are in accordance with the original plan prescribed in Veridian's 2010 cost of service application and the Board's decision in Veridian's 2011 IRM application.

VECC however submitted that the 2012 workform should be revised to include an allocation of the revenue offsets approved in its last cost of service application.

In its reply submission, Veridian noted that, in its decision on Veridian's 2011 IRM application, the Board accepted Veridian's proposed revenue-to-cost ratio adjustments based on its original filing with no amounts included for revenue offsets in the workform. Veridian submitted that VECC's request to resubmit a revised workform to incorporate the revenue offsets for 2012 rates would serve no purpose as Veridian's current treatment of the revenue offsets is the same as that agreed to by VECC and accepted by the Board in the 2011 proceeding.

The Board approves the 2012 proposed revenue-to-cost ratio adjustments for the Gravenhurst service area. The Board will not require the model changes sought by VECC as they are inconsistent with both the Board's decision in Veridian's 2010 cost of service application and the Board's decision in Veridian's 2011 IRM application. The Board finds that the proposed revenue-to-cost ratios are consistent with the phase-in period in EB-2009-0140.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction over the IRM plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

Veridian's application identified a total tax savings of $954,203 for the Main service area and $18,404 for the Gravenhurst service area, resulting in a shared amount of $477,101 and $9,202, respectively, to be refunded to rate payers.

The Board approves the disposition of the shared tax savings of $477,101 for the Main service area and $9,202 for the Gravenhurst service area over a one-year period (i.e. May 1, 2012 to April 30, 2013) and the associated rate riders for all customer rate classes.

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2011 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2012. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table:

2012 Uniform Transmission Rates

Network Service Rate	$3.57 per kW
Connection Service Rates Line Connection Service Rate Transformation Connection Service Rate	 $0.80 per kW $1.86 per kW

The Board finds that these 2012 UTRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Veridian – Main's 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a credit of $9,063,286. This amount results in a total credit claim of $0.00382 per kWh, which exceeds the preset disposition threshold. Veridian proposed to dispose of this credit amount over a two-year period.

Veridian – Gravenhurst's 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a credit balance of $569,013. This amount results in a total credit claim of $0.00628 per kWh, which exceeds the preset disposition threshold. Veridian proposed to dispose of this credit amount over a two-year period.

With respect to the disposition of the global adjustment sub-account, Veridian noted that it received regulatory approval for a separate rate rider that is included in the electricity component of the bill and applies to non-RPP customers only.

In response to Board staff interrogatory #13, Veridian indicated that following a RPP (Form 1598) Electricity Refunds Claim Audit with the Ministry of Finance, amounts related to 2009 balances were identified and recorded with the appropriate accounts to be included within the 2010 year-end balances and included in Veridian's 2010 *Reporting and Record-keeping* Requirement ("RRR") filings. Those adjustments pertaining to 2009 were taken into consideration in the Group 1 account balances for which disposition is sought in the current application.

Subsequent to the 2010 RRR filings, adjustments to Account 1588 related to 2010 activities were identified. These adjustments were not reflected in Veridian's final 2010 RRR filings and were not included in the Group 1 Account balances for which disposition is sought in this proceeding.

In its submission, Board staff requested that Veridian provide the adjustments to Account 1588 and the details of the nature of these adjustments in its reply submission. Board staff also expressed concerns that Veridian did not attempt to amend its 2010 RRR filings to reflect these adjustments to Account 1588. Board staff noted that the Board issued a letter on February 17, 2010 to electricity distributors concerning revising data filed under RRR stating the importance and legal obligations of compliance with the Board's RRR.

Board staff submitted that regardless of whether the Board approves the inclusion of these adjustments in Account 1588, Board staff agrees with Veridian's proposal for a two-year disposition period as this would strike a balance between reducing intergenerational inequity and mitigating rate volatility.

Board staff also submitted that with respect to the bill presentation of the global adjustment rate rider, consistency across distributors, where possible, would allow for more meaningful comparison of the rates charged by distributors and how customers are being billed. Board staff argued that the Board should consider directing Veridian to include a separate global adjustment rate rider that would apply prospectively to non-RPP customers in the delivery component of the bill.

In its reply submission, Veridian updated its Group 1 account balances to include the adjustments to Account 1588 related to 2010 activities along with interest projected to April 30, 2012. The updated balances are a credit balance of $4,764,273 for Veridian – Main and a credit balance of $431,196 for Veridian – Gravenhurst. Veridian noted that the preset disposition threshold would be exceeded for both service areas with these updated balances.

Veridian explained that the adjustments to Account 1588 were due to formula errors identified in Veridian's spreadsheet calculations of the Regulated Price Plan ("RPP") and global adjustment settlement amounts with the Independent Electricity System Operator (the "IESO") in 2010. These errors were identified through a review conducted by the Ministry of Finance of Veridian's records supporting monthly requests to the IESO under the RPP. Veridian further noted that these adjustments were not finalized until late August 2011 and were included in the September 2011 IESO submissions and the September settlement amount. These adjustments were recorded to the appropriate accounts in September 2011.

Veridian agreed with Board staff that it would have been appropriate to request restatement of the 2010 RRR filings to include the 2010 portion of the September 2011 adjustments.

Veridian submitted that on the basis of rate stability, it is appropriate for the Board to include the adjustments to the balances of Account 1588 proposed for disposition. Veridian noted that if these adjustments are not made to the amounts refunded in this proceeding, the balances that would be disposed of would be overstated, and a subsequent recovery from ratepayers would be required in a future rate year.

With respect to the bill presentation of the Global Adjustment sub-account rate rider, Veridian submitted that continuing its current practice of presenting the Global Adjustment rate riders as part of the electricity component of the bill offers the benefit of consistency with its past practice and would reduce the potential for customer confusion. Veridian indicated that it does have the billing capability and would not object to charging the Global Adjustment rate riders on the delivery component of the bill, if so directed by the Board.

The Board approves, on a final basis, the disposition of a credit balance of $4,764,273 as of December 31, 2010, including interest as of April 30, 2012 for Group 1 accounts for Veridian – Main and a credit balance of $431,196 as of December 31, 2010, including interest as of April 30, 2012 for Group 1 accounts for Veridian – Gravenhurst. These balances are to be disposed over a two-year period from May 1, 2012 to April 30, 2014, which reflects the need to balance intergenerational inequity issues with the need to mitigate rate volatility.

The Board also directs Veridian that the disposition of the Global Adjustment sub-account rate rider be reflected in the delivery component of the bill for non-RPP customers. The Board is mindful of the need for a consistent approach across distributors and Veridian has confirmed that it has the billing capability to include the Global Adjustment sub-account rate rider in the delivery component of the bill.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts for Veridian – Main.

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	-$1,826,971	-$54,653	-$1,881,624
RSVA - Wholesale Market Service Charge	1580	-$3,382,929	-$120,854	-$3,503,783

RSVA - Retail Transmission Network Charge	1584	$2,280,146	$34,468	$2,314,614
RSVA - Retail Transmission Connection Charge	1586	$2,035,246	$7,285	$2,042,531
RSVA - Power (excluding Global Adjustment)	1588	-$15,043,797	$5,865,403	-$9,178,394
RSVA - Power – Global Adjustment Sub-Account	1588	$7,143,369	-$1,700,985	$5,442,384
Group 1 Total				**-$4,764,273**

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts for Veridian – Gravenhurst.

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	-$77,829	-$774	-$78,603
RSVA - Wholesale Market Service Charge	1580	-$150,456	-$4,972	-$155,428
RSVA - Retail Transmission Network Charge	1584	37,122	$601	$37,723
RSVA - Retail Transmission Connection Charge	1586	52,561	$838	$53,399
RSVA - Power (excluding Global Adjustment)	1588	-$551,256	$188,536	-$362,720
RSVA - Power – Global Adjustment Sub-Account	1588	$130,101	-$55,668	$74,433
Group 1 Total				**-$431,196**

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Account 1521: Special Purpose Charge

The Board authorized Account 1521, Special Purpose Charge Assessment ("SPC") Variance Account in accordance with Section 8 of *Ontario Regulation 66/10* (*Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs*) (the "SPC Regulation"). Accordingly, any difference between (a) the amount remitted to the Minister of Finance for the distributor's SPC assessment and (b) the amounts recovered from customers on account of the assessment were to be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors are required to apply by no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance. The Filing Requirements state the Board's expectation that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

In the Manager's Summary of its application, Veridian indicated that due to a system oversight, the recovery period for the SPC was extended for three months past the specified one-year period. As a result, over recovery from some customers occurred. Veridian noted that it had identified the specific customers by whom overpayment was made and refunded the amounts to those customers. Veridian indicated that the total SPC principal and interest to April 30, 2012 was a debit of $59,791 for Veridian – Main and a debit of $2,402 for Veridian – Gravenhurst.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, including carrying charges, plus the amount recovered from customers in 2011, including carrying charges, because the account balance does not require a prudence review and electricity distributors are required by regulation to apply for disposition of this account. Board staff also submitted that Veridian's proposal to allocate the balance in Account 1521 to Veridian – Main and Veridian – Gravenhurst using Veridian's 2008 wholesale kWhs is reasonable.

In its reply submission, Veridian noted that the amount refunded to customers that were over charged in error was updated from $185,213 to $110,293. Veridian also noted that the corrected principal balance for Account 1521 as of December 31, 2011, including carrying charges as of April 30, 2012 is a credit of $14,251.

The Board approves, on a final basis, the disposition of Account 1521 as of December 31, 2010 including carrying charges plus the amounts recovered in 2011, plus projected carrying charges to April 30, 2012, for a total credit balance of $14,251. Consistent with the Board's findings on the disposition of Group 1 Account balances, the Board approves a disposition period of two years. The Board directs that Account 1521 be closed effective May 1, 2012.

For accounting and reporting purposes, the balance of Account 1521 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Lost Revenue Adjustment Mechanism ("LRAM")

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on March 28, 2008 outline the information that is required when filing an application for LRAM or SSM.

Veridian originally requested the recovery of an LRAM claim of $1,388,731 over a one-year period. Veridian's LRAM claim includes lost revenues from programs delivered in 2007 to 2010 as well as persisting effects from 2005 to 2006 programs.

Board staff submitted that it supports the approval of the 2007 to 2009 lost revenues in 2007 to 2009 as requested by Veridian as these lost revenues took place during IRM years and Veridian did not previously recover these amounts. However, Board staff did not support the persisting lost revenues from 2005 to 2009 CDM programs in 2010 and the lost revenues persisting beyond 2010 as these amounts should have been incorporated into Veridian's last approved load forecast. Board staff requested that Veridian provide an updated LRAM amount that only includes lost revenues from 2007 to 2009 and the associated rate riders.

VECC noted that Veridian indicated that the approved May 1, 2010 distribution rates were based on a load forecast that excluded the impacts of CDM programs. VECC submitted that the energy savings from CDM programs implemented between 2005 and 2010 (and beyond) are not accruable in 2010 as savings should have been incorporated in the 2010 load forecast at the time of rebasing. VECC supported the approval of lost revenues required by Veridian for CDM programs implemented in 2005 to 2007 with persisting effects in the year 2008 and 2009 as Veridian did not collect this revenue while under IRM. VECC also supported the approval of lost revenues requested by Veridian for CDM programs implemented in 2007 to 2009 for the years 2007 to 2009 as Veridian did not collect this revenue while under IRM. VECC submitted that the LRAM claim and rate riders approved by the Board should be adjusted to exclude the proposed lost revenue in 2010 from CDM programs implemented between 2005 and 2010.

In its reply submission, Veridian provided the updated information requested by Board staff. Veridian noted that the lost revenue from 2007 to 2009 is $822,961.

Veridian also noted that the parties in Veridian’s 2010 cost of service proceeding specifically agreed to exclude the CDM initiatives from Veridian’s forecast because details regarding OPA programs in the test year were not available at the time that the load forecast was prepared. Therefore, the parties, including VECC, agreed to depart from the methodology contemplated by the Guidelines due to the lack of available information. Veridian further noted that Board staff was involved in the settlement negotiation and if Board staff had concerns about the departure from the methodology contemplated by the Guidelines, Board staff should have raised the concern with the Board.

Veridian submitted that the wording from the 2012 CDM Guidelines is not found in the 2008 CDM Guidelines and, therefore, Board staff has suggested that the Board retroactively impose a requirement that did not exist at the time Veridian entered into the Settlement Agreement. Veridian also submitted that its expectation of future recovery can easily be inferred from the Settlement Agreement, since the stated reason for omitting CDM impacts from the 2010 load forecast was “lack of available information” at the time. Veridian noted it logically follows that once the necessary information became available, Veridian would use it to address CDM impacts in the 2010 test year. Veridian never agreed to forego its lost revenues from its 2010 CDM programs.

Veridian also noted that the regression model used for the load forecast projected 2010 sales volumes (i.e. revenue) based on a historic dataset of wholesale power deliveries from May 2002 to December 2008, since Veridian did deliver CDM programs during this time period, some historical savings were captured and projected into the test year. However, Veridian submitted that these implicit savings in its 2010 load forecast are approximately 22% of the actual 2010 impact of its 2005 to 2010 CDM programs. Veridian proposed that its original LRAM amount be reduced to account for this circumstance.

Veridian maintained that it should be awarded the full LRAM amount of $1,389,688 for lost revenues in years 2007 to 2010. Alternatively, Veridian noted that it would be willing to accept a discounted 2010 LRAM amount to account for the 22% mentioned above. Veridian also advised the Board that it intends to file for recovery of unclaimed lost revenues up to and including its next rebasing (i.e. January 1, 2011 to April 30, 2014) in a future LRAM application.

The Board will not approve the LRAM claim as originally filed by Veridian. The Board will approve an LRAM claim of $822,961 representing the lost revenue associated with persistence from the legacy programs implemented in 2007 to 2009. The Board will not approve the stub period claim, as it is not the current practice of the Board and was not tested during the proceeding.

With respect to the LRAM claim associated with the effect of 2010 programs in the 2010 rate year and persistence from legacy programs in 2010, the Board finds that it would be inappropriate to deviate from the 2008 Guidelines, which state that lost revenues are accruable until new rates are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. The Board notes the assertion in the Settlement Agreement that “Veridian has not included any CDM program impacts in the 2010 load forecast” has been contradicted by Veridian’s response to Board staff interrogatory #14 this proceeding, which states that approximately 22% of the 2010 impacts of Veridian’s 2005 to 2010 CDM programs are included in the approved 2010 load forecast. As set out in the Hydro Ottawa decision (EB-2011-0054), the current CDM Guidelines do not consider a true-up of the effects of CDM activities embedded in the rebasing year. As such, there is no reasonable basis for the Board to vary from the existing CDM Guidelines.

The Board reminds Veridian that the draft CDM Guidelines posted January 5, 2012 provide guidance on the proposed details on the LRAM related to CDM programs implemented under the CDM Code, i.e. those effective for the 2011 to 2014 period.

The Board will not opine on the appropriateness of Veridian's intention to file for recovery of unclaimed lost revenues up to and including its next rebasing as the policy for the treatment of LRAM for the year 2011 and beyond have not yet been developed.

Rate Model

With this Decision, the Board is providing Veridian with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2011 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Veridian's new distribution rates shall be effective May 1, 2012.

2. Veridian shall review the draft Tariff of Rates and Charges set out in Appendix A. Veridian shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision and Order.

3. If the Board does not receive a submission from Veridian to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Order will become final effective May 1, 2012, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2012. Veridian shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Veridian to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Veridian and will issue a final Tariff of Rates and Charges.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Veridian shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to Veridian any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Veridian shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0199,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

DATED at Toronto, March 22, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2011-0199

DATED: March 22, 2012

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst

RESIDENTIAL SERVICE CLASSIFICATION

All residential customers with kilowatt-hour meters shall be deemed to have a demand of 50kW or less. This customer classification includes Single Family Homes, Street Townhouses, Multiplexes, and Block Townhouses. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.18
Distribution Volumetric Rate	$/kWh	0.0157
Low Voltage Service Rate	$/kWh	0.0006
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0022)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13.81
Distribution Volumetric Rate	$/kWh	0.0170
Low Voltage Service Rate	$/kWh	0.0005
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0022)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst

GENERAL SERVICE 50 to 2,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	136.15
Distribution Volumetric Rate	$/kW	3.0492
Low Voltage Service Rate	$/kW	0.2462
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.8292)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0400)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0203
Retail Transmission Rate – Network Service Rate	$/kW	2.7689
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7703

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0199

For All Service Areas Except Gravenhurst

GENERAL SERVICE 3,000 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average peak demand used for billing purposes over the past twelve months is equal to or greater than, or forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5,389.69
Distribution Volumetric Rate	$/kW	1.4260
Low Voltage Service Rate	$/kW	0.2710
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.8045)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0312)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.0384
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9484

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0199

For All Service Areas Except Gravenhurst

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	8,096.42
Distribution Volumetric Rate	$/kW	1.6985
Low Voltage Service Rate	$/kW	0.2710
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.1503)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0347)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0095
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.0384
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9484

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

In general, all services will be metered. However, certain types of electrical loads are not practical to meter, or the cost of metering represents an inordinate expense to both the Customer and Veridian. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. These situations can be managed through a controlled connection and a pre-defined basis for estimating consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	7.55
Distribution Volumetric Rate	$/kWh	0.0187
Low Voltage Service Rate	$/kWh	0.0005
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0022)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst

SENTINEL LIGHTING SERVICE CLASSIFICATION

Sentinel lights (dusk-to-dawn) connected to unmetered wires will have a flat rate monthly energy charge added to the regular customer bill. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	3.56
Distribution Volumetric Rate	$/kW	11.0694
Low Voltage Service Rate	$/kW	0.1527
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.7740)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.2591)
Retail Transmission Rate – Network Service Rate	$/kW	1.7151
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0980

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street or roadway lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.66
Distribution Volumetric Rate	$/kW	3.6657
Low Voltage Service Rate	$/kW	0.1609
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.7697)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0020
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0806)
Retail Transmission Rate – Network Service Rate	$/kW	1.8110
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1569

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For All Service Areas Except Gravenhurst

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
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For All Service Areas Except Gravenhurst

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Customer Substation Isolation - After Hours	$	905.00

Veridian Connections Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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EB-2011-0199

For All Service Areas Except Gravenhurst

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0442
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0146
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0338
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
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For Gravenhurst Service Area

RESIDENTIAL SERVICE CLASSIFICATION

Urban Density:
An urban density area is defined as containing 100 or more customers with a line density of at least 15 customers per kilometer of distribution line and includes both Year-Round and Seasonal sub groups.

Suburban Density:
A suburban density area is defined as any area that is not designated as an urban density area.

Residential Year-Round
This classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as year-round residential, all of the following criteria must be met:
1. The occupant must state that this is designated as the principal residence for purposes of the Income Tax Act.
2. The occupant must live in this residence for at least 8 months of the year.
3. The address of this residence must appear on the occupant's electric bill, driver's license, credit card invoice, property tax bill, etc
4. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Residential Suburban Seasonal
This classification is comprised of cottages, chalets, and camps, all Farms supplied from single-phase facilities and any residential service not meeting the Residential Year-Round criteria.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
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For Gravenhurst Service Area

RESIDENTIAL URBAN YEAR-ROUND

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	10.06
Distribution Volumetric Rate	$/kWh	0.0194
Low Voltage Service Rate	$/kWh	0.0029
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	0.0030
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0028)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0009
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0001)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

RESIDENTIAL SUBURBAN YEAR-ROUND

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	18.42
Distribution Volumetric Rate	$/kWh	0.0253
Low Voltage Service Rate	$/kWh	0.0029
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	0.0030
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0028)
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0001)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

RESIDENTIAL SUBURBAN SEASONAL

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	26.72
Distribution Volumetric Rate	$/kWh	0.0330
Low Voltage Service Rate	$/kWh	0.0029
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0028)

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Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0009
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0062
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
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For Gravenhurst Service Area

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

The General Service classification is applicable to any service that does not fit the description of the Residential classes. Generally, it is comprised of commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	9.95
Distribution Volumetric Rate	$/kWh	0.0168
Low Voltage Service Rate	$/kWh	0.0026
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	0.0030
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0028)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0009
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0001)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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For Gravenhurst Service Area

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

The General Service classification is applicable to any service that does not fit the description of the Residential classes. Generally, it is comprised of commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	103.55
Distribution Volumetric Rate	$/kW	3.8174
Low Voltage Service Rate	$/kW	0.9486
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	1.2281
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.1651)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0009
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0159)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0203
Retail Transmission Rate – Network Service Rate	$/kW	2.3122
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7954

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account that is an unmetered lighting load supplied to a sentinel light, which is assumed to have the same hourly consumption load profile as street lighting. Metered sentinel lighting is captured under the consumption of the principal service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	3.00
Distribution Volumetric Rate	$/kW	5.6885
Low Voltage Service Rate	$/kW	0.7486
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	0.9363
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.0044)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0009
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0520)
Retail Transmission Rate – Network Service Rate	$/kW	1.7526
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4169

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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For Gravenhurst Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.43
Distribution Volumetric Rate	$/kW	0.4098
Low Voltage Service Rate	$/kW	0.7333
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	1.0537
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.9611)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0009
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0111)
Retail Transmission Rate – Network Service Rate	$/kW	1.7439
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3877

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Veridian Connections Inc.
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For Gravenhurst Service Area

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

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For Gravenhurst Service Area

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

Veridian Connections Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0199

For Gravenhurst Service Area

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.1013
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0903

Appendix B

Ontario Energy Board **Commission de l'énergie de l'Ontario**

EB-2011-0153

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Bluewater Power Distribution Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

BEFORE: Karen Taylor
Presiding Member

Paula Conboy
Member

DECISION AND ORDER

Introduction

Bluewater Power Distribution Corporation ("Bluewater"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 3, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Bluewater charges for electricity distribution, to be effective May 1, 2012.

Bluewater is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, establishes a three year plan term for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed

Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the 3rd generation IRM plan until such time as the RRFE policy initiatives have been substantially completed. As part of the plan, Bluewater is one of the electricity distributors that will have its rates adjusted for 2012 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "*Supplemental Report*"), and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports contain the relevant guidelines for 2012 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 22, 2011 the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the Filing Requirements for IRM applications based on the policies in the Reports.

Notice of Bluewater's rate application was given through newspaper publication in Bluewater's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors would be eligible for cost awards with respect to Bluewater's proposed revenue-to-cost ratio adjustments and its request for lost revenue adjustment mechanism ("LRAM") recoveries. The Vulnerable Energy Consumers Coalition ("VECC") applied for and was granted intervenor status in this proceeding. The Board granted VECC eligibility for cost awards in regards to Bluewater's request for LRAM recoveries and any revenue-to-cost ratio matters that go beyond the implementation of previous Board decisions. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection;
- Revenue-to-Cost Ratio Adjustments;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Review and Disposition of Account 1521: Special Purpose Charge;
- Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes;
- Review and Disposition of Lost Revenue Adjustment Mechanism; and
- Smart Meter Funding Adder.

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator, less a productivity factor (X-factor) of 0.72% and a stretch factor.

On March 13, 2012, the Board announced a price escalator of 2.0% for those distributors under IRM that have a rate year commencing May 1, 2012.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated December 1, 2011 the Board assigned to Bluewater efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes that are not eligible for Rural or Remote Electricity Rate Protection. The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;

- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The final Tariff of Rates and Charges attached to this Decision and Order reflects the new RRRP charge.

Revenue-to-Cost Ratio Adjustments

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges (the "Target Ranges") for Ontario electricity distributors in its report *Application of Cost Allocation for Electricity Distributors*, dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy,* dated March 31, 2011.

Pursuant to the Settlement Proposal approved by the Board in Bluewater's 2009 cost of service application [EB-2008-0221], it was agreed that for the 2012 rate year Bluewater would adjust the Street Lighting and Sentinel Lighting categories to a revenue-to-cost ratio of 0.85. The excess revenue would be allocated to the General Service Less Than 50 kW and Large Use rate classes.

The table below outlines the proposed revenue-to-cost ratios.

Rate Class	Current 2011 Ratio	Proposed 2012 Ratio	Target Range
Residential	103.00%	103.00%	85 – 115
General Service Less Than 50 kW	104.85%	103.00%	80 – 120
General Service 50 to 999 kW	90.00%	90.00%	80 – 180
General Service 1,000 to 4,999 kW	101.00%	101.00%	85 – 115
Large Use	104.85%	103.00%	80 – 120
Street Lighting	75.33%	85.00%	70 – 120
Sentinel Lighting	72.33%	85.00%	70 – 120
Unmetered Scattered Load	80.00%	85.00%	80 – 120

Both Board staff and VECC submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board approved Settlement Agreement in Bluewater’s 2009 cost of service proceeding.

The Board approves the proposed revenue to cost ratios as the proposed adjustments are in accordance with EB-2008-0221.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction over the IRM plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

Bluewater’s application identified a total tax savings of $505,462 resulting in a shared amount of $252,731 to be refunded to rate payers.

In its submission, Board staff noted that Bluewater completed the Tax-Savings Workform with the correct rates which reflected the Revenue Requirement Work Form from the Board's Decision in EB-2008-0221. Board staff had no concerns with the workform filed.
The Board approves the disposition of the shared tax savings amount of a credit of $252,731 over a one year period (i.e. May 1, 2012 to April 30, 2013).

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2011 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2012. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table:

2012 Uniform Transmission Rates

Network Service Rate	$3.57 per kW
<u>Connection Service Rates</u>	
Line Connection Service Rate	$0.80 per kW
Transformation Connection Service Rate	$1.86 per kW

In its submission, Board staff noted that it has no concerns with the RTSR Workform as filed by Bluewater.

The Board finds that these 2012 UTRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Bluewater's 2010 actual year-end balance for Group 1 Accounts including interest projected to April 30, 2012 is a credit of $2,112,461. This amount results in a total claim of -$0.00203 per kWh, which exceeds the preset disposition threshold. Bluewater proposed to dispose of this credit amount over a two year period.

In interrogatories, Board staff noted variances between Bluewater's RRR filings and its December 31, 2010 ending balances. In its response, Bluewater noted that it had analyzed its Group 1 Accounts and noted that these variances were the result of the difference between i) the actual amount of carrying charges based on prescribed rates recorded in previous years by Bluewater and ii) the OEB approved disposition amounts which included forecast carrying charges at the time of the respective rate applications. Bluewater noted that it intends to allocate these historical variances to either Account 4405 or 6035 to reverse these charges.

In its submission, Board staff noted that Bluewater's explanation for the variances between its RRR and December 31, 2010 Group 1 Deferral and Variance Account balances is reasonable. Also, Board staff took no issue with Bluewater's request to dispose of its 2010 Group 1 Account balances at this time over the requested two year period to allow for the smoothing of rates.

With respect to the allocation of the variances to either Account 4405 or 6035, Board staff noted that this should not be done as these variances will be trued-up as part of

Bluewater's future rate proceeding, when the residual balance in the recoveries account 1595 should be disposed.

The Board notes that the disposition threshold of $0.001 has been exceeded. Accordingly, the Board will approve the disposition of Bluewater's Group 1 Deferral and Variance Account balances of a credit of $2,112,461 on a final basis as of December 31, 2010 plus interest to April 30, 2012. The Board approves a disposition period of two years - May 1, 2012 to April 30, 2014, as requested by Bluewater. The Board is of the view that a two-year disposition period appropriately aligns the issues of intergenerational equity with the need to mitigate rate volatility. The Board concurs with Board staff that Bluewater should not undertake the reallocation of variances to either Account 4405 or 6035, as these variances should be trued-up in a future proceeding.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

Account Name	Account Number	Principal Balance	Interest Balance	Total Claim
LV Variance Account	1550	-$66,902	-$2,653	-$69,555
RSVA - Wholesale Market Service Charge	1580	-$1,369,743	-$36,832	-$1,406,575
RSVA - Retail Transmission Network Charge	1584	-$57,194	-$1,158	-$58,352
RSVA - Retail Transmission Connection Charge	1586	-$112,481	-$4,600	-$117,081
RSVA - Power (excluding Global Adjustment)	1588	-$213,825	$11,359	-$202,466
RSVA - Power - Sub-Account - Global Adjustment	1588	-$275,380	$16,948	-$258,432
Disposition and Recovery of Regulatory Balances (2008)	1595			-
Disposition and Recovery of Regulatory Balances (2009)	1595			-
Group 1 Total				**-$2,112,461**

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Account 1521: Special Purpose Charge

The Board authorized Account 1521, Special Purpose Charge Assessment ("SPC") Variance Account in accordance with Section 8 of Ontario Regulation 66/10 (Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs) (the "SPC Regulation"). Accordingly, any difference between (a) the amount remitted to the Minister of Finance for the distributor's SPC assessment and (b) the amounts recovered from customers on account of the assessment were to be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance. The Filing Requirements state the Board's expectation that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

Bluewater requested the disposition of a residual debit balance of $2,709 as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, plus the amounts recovered from customers in 2011, including interest, because the account balance does not require a prudence review, and electricity distributors are required by regulation to apply for disposition of this account. Board staff submitted that the $2,709 debit balance in Account 1521 should be approved for disposition on a final basis.

The Board approves, on a final basis, Bluewater's request for the disposition of the principal and interest balances in Account 1521 totaling a debit of $2,709 over a two year period, consistent with the Board's findings on Bluewater's Group 1 Deferral and Variance account balances. The Board directs Bluewater to close account 1521 as of May 1, 2012.

For accounting and reporting purposes, the balance of Account 1521 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes

In 2001, the Board approved a regulatory payments in lieu of taxes proxy approach for rate applications coupled with a true-up mechanism filed under the RRR to account for changes in tax legislation and rules and to true-up between certain proxy amounts used to set rates and the actual amount of taxes paid. The variances resulting from the true-up were tracked in Account 1562 for the period 2001 through April 30, 2006.

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Board commenced a Combined Proceeding (EB-2008-0381) on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications.

The Notice in the Combined Proceeding included a statement of the Board's expectation that the decision resulting from the Combined Proceeding would be used to determine the final account balances with respect to Account 1562 Deferred PILs for the remaining distributors. In its decision and order, the Board stated that: "Each remaining distributor will be expected to apply for final disposition of account 1562 with its next general rates application (either IRM or cost of service)."[1]

[1] EB-2008-0381 Account 1562 Deferred PILs Combined Proceeding, Decision and Order, p. 28

Bluewater applied to dispose of a credit balance of $638,656 which included a principal balance of a credit of $555,943 and carrying charges up to April 30, 2012 of $82,713 over a two year period.

<u>CDM Incremental OM&A Expenses</u>

Board staff requested Bluewater to clarify whether the company incurred and disclosed expenses related to CDM activities in its 2005 financial statements as a component of net income; and, that Bluewater provide an explanation for the difference in the amounts disclosed in the interrogatory response of $104,549 for CDM costs incurred and in the financial statements of $362,532.

Board staff noted that If Bluewater incurred CDM expenses in its 2005 net income, Bluewater should select one of two options: 1) Record the 2005 actual CDM expense of $104,549 (or $362,532) in 2005 SIMPIL model TAXCALC sheet; or, 2) Move the CDM proxy amount of $127,600 to a line that does not true-up. Further, Board staff noted that if Bluewater had deferred all CDM capital and operating expenses amounting to $362,532 as at December 31, 2005 in account 1565, Bluewater should explain whether those CDM amounts have been disclosed on 2005 SIMPIL sheet TAXREC3 as part of the changes in regulatory assets, and if so, where specifically they were disclosed.

Other than the possible adjustment for CDM expenses as discussed above, and any resulting changes to interest carrying charges, Board staff submitted that Bluewater followed the regulatory guidance and the Board's decisions in determining the amounts recorded in Account 1562.

In its reply submission, Bluewater proposed to follow Board Staff's recommendation #1 as indicated above. As a result, the revised Account 1562 balance is a credit of $706,229 consisting of a principal credit amount of $614,040 plus related credit carrying charges of $92,189.

The Board approves the disposition of a credit balance of $706,229 on a final basis as at April 30, 2012 over a two year period, consisting of a principal credit amount of $614,040 plus carrying charges of $92,189. The two year disposition period is consistent with the Board's findings on Bluewater's Group 1 Deferral and Variance account balances.

For accounting and reporting purposes, the balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the Accounting Procedures Handbook for Electricity Distributors. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Lost Revenue Adjustment Mechanism

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on March 28, 2008 outline the information that is required when filing an application for LRAM or SSM.

Initially, Bluewater had applied for an LRAM amount of $303,393.37 to be recovered over a one year period. In response to interrogatories from Board staff and VECC, Bluewater updated its LRAM amount with the 2010 OPA final results to $308,567.16 The lost revenues include the effect of new 2010 programs as well as persistence of 2006-2009 programs in 2010, and the persistence of 2006-2010 programs for 2011.

<u>2006-2009 Persisting Programs</u>

Board staff submitted that the *Guidelines for Electricity Distributor Conservation and Demand Management* ("CDM Guidelines") state the following:

> Lost Revenues are only accruable until new rates (based on a new revenue requirement and load forecast are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.[2]

Board staff noted that in cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application in this proceeding is appropriate. Board staff requested that

[2] EB-2008-0037, Section 5.2

Bluewater highlight in its reply whether the issue of an LRAM application was addressed in its most recent cost of service application.

Board staff submitted that in the absence of the above information, Bluewater should not be permitted to recover the requested persisting lost revenues from 2006-2009 CDM programs in 2010 or 2011 as these amounts should have been built into Bluewater's last approved load forecast, thereby dispensing with the need for LRAM.

VECC submitted that the load forecast methodology utilized by Bluewater and subsequently approved by the Board in its 2009 cost of service application included actual use and therefore included 2006 to 2007 CDM program impacts. VECC further submitted that Bluewater's regression model would capture not only historical savings but would carry forward into future years trends in the historical data regarding increased CDM savings over time that would be implicit in the 2009 forecast.

As a result, VECC submitted that there is already recognition of lost sales (and therefore revenues) in 2009 from additional 2008 and 2009 CDM programs accounted for in the 2009 load forecast. As there is no information available to indicate whether the savings implicitly included in the 2009 forecast are more or less than the actual impact of 2006 to 2009 CDM programs in 2009, VECC submitted that based on these considerations and the Board's Guidelines, lost revenue for Bluewater's 2006 to 2009 programs that persist into 2010 and 2011 are not accruable in 2010 and 2011.

In its reply submission, Bluewater noted that it did not include any CDM impacts in its load forecast and expected that it would be able to recover amounts through an LRAM application. Bluewater referred to the 2009 Settlement Agreement which states, "[f]or the sake of clarity, the revised forecast does not reflect in any way specific electricity conservation programs". Bluewater submitted that this last sentence in the Settlement Agreement served the sole purpose of highlighting its expectation that it would seek to recover lost revenues through a future LRAM claim.

<u>2010 Programs</u>

Bluewater has also requested the recovery of new savings arising from CDM programs delivered in 2010 and persisting savings from these programs through 2011.

Board staff submitted that Bluewater was under IRM in 2010 and therefore it could not have been reasonably expected to account for these new program savings at the time it rebased and had a new load forecast approved by the Board. Board staff supported the recovery of the lost revenues related to the new savings arising from 2010 programs. Board staff noted that the Board requested distributors to file for recovery of any and all LRAM amounts related to 2005-2010 CDM programs in their 2012 rate applications. Board staff suggested that Bluewater provide an updated LRAM amount for only 2010 program savings that took place in 2010, allocated by rate class, in its reply submission. VECC submitted that Bluewater calculated estimated lost revenues for 2006 to 2010 CDM Programs in 2011 based on the OPA's Measures and Assumptions list and OPA verified results available at the time of this application, which is not appropriate or in accordance with the Guidelines. VECC further submitted that in the absence of OPA input assumptions and verified final results for 2011, the LRAM claim should be adjusted to cover only lost revenues from new 2010 CDM programs in 2010.

In its reply, Bluewater referred to Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications and noted that, if this proceeding is its last opportunity to recover LRAM from 2006-2010 programs, including persistence in 2011 and 2012, it is appropriate to include 2012 amounts at this time, but only if the Board directs that this is Bluewater's last opportunity to claim these savings.

The Board acknowledges and accepts the provision in the Settlement Agreement relating to EB-2008-0221, which states: "For the sake of clarity, the revised forecast does not reflect in any way specific electricity conservation programs". Accordingly, the Board will approve LRAM recovery for the persistence of 2006 – 2009 programs in 2010 and the effect in 2010 of the programs implemented in 2010, totalling $168,049.85 to December 31, 2010, plus interest to April 30, 2012. The Board will not approve recovery of persistence from 2006 to 2010 programs in 2011 and 2012, as it is premature to do so and inconsistent with the LRAM Guidelines. The Board approves a two year disposition period (i.e., May 1, 2012 to April 30, 2014), consistent with the Board's findings elsewhere in this Decision.

Smart Meter Funding Adder ("SMFA")

Bluewater requested that the Board approve the continuation of its current SMFA of $2.00 to April 30, 2013. Bluewater noted that although the physical deployment of Smart Meters was completed in 2011, Bluewater is experiencing delays in implementing TOU pricing. The Board approved the extension of the date for mandated TOU billing from October 2011 to January 31, 2012.

Board staff submitted that the Board could consider continuance of the current $2.00 SMFA with a specific sunset date. Board staff noted that establishing a sunset date of October 31, 2012 would be suitable. By this time, Bluewater should have completed its smart meter program, including TOU implementation. Bluewater’s 2011 costs would also be audited by then, so that total smart meter costs should satisfy the threshold that at least 90% of such costs are audited actuals.

In its reply submission, Bluewater stated that while it respects the intent of Board staff’s submission of a sunset date of October 31, 2012, Bluewater believes that the proposed date is not practical, given the fact that there remains some uncertainty surrounding the implementation of Bluewater’s TOU program. The October 31, 2012 date would deny Bluewater the option to submit its Smart Meter costs for final disposition as part of its 2013 rebasing application, despite that mechanism specifically being contemplated by the recent filing guidelines (i.e. G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition).

The Board has determined that it will not approve the continuation of the existing SMFA of $2.00 per metered customer per month past the present expiry date of April 30, 2012. The Board is of the view that the TOU date is not the relevant metric to consider with respect to whether it is appropriate to extend a SMFA. Rather, the relevant metric is the date by which smart meter deployment was or will be substantially completed. In this case, smart meter deployment was completed in August 2011. The SMFA was designed to fund the prospective deployment of smart meters with minimum functionality. It was not intended to fund the activities referenced by Bluewater, which are clearly outside of the minimum functionality pursuant to O. Reg. 425/06, the functional specification for an Advanced Metering Infrastructure issued on July 5, 2007, the Board’s Decision in EB-2007-0063[3], and SMFA and Cost Recovery guidelines dated October 22, 2008[4].

The Board disagrees with Bluewater’s interpretation of Guideline G-2011-0001, as final disposition in a cost of service is only one of the alternatives contemplated. The Board believes that the current sunset date best aligns the interests of ratepayers and the

[3] Smart Meter Initiative Combined Proceeding (EB-2007-0063)
[4] Guideline: Smart Meter Funding and Cost Recovery (G-2008-0002)

utility by balancing regulatory efficiency and streamlining with the need to ensure that monies collected from ratepayers serve the intended purpose and are adequately supported by appropriate amounts.

Rate Model

With this Decision, the Board is providing Bluewater with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2011 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Bluewater's new distribution rates shall be effective May 1, 2012.

2. Bluewater shall review the draft Tariff of Rates and Charges set out in Appendix A. Bluewater shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision and Order.

3. If the Board does not receive a submission from Bluewater to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this order will become final effective May 1, 2012, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2012. Bluewater shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Bluewater to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Bluewater and will issue a final Tariff of Rates and Charges.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.
2. Bluewater shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.
3. VECC shall file with the Board and forward to Bluewater any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.
4. Bluewater shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0153,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, March 22, 2012
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2011-0153

DATED: March 22, 2012

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

RESIDENTIAL SERVICE CLASSIFICATION

All service supplied to single-family dwelling units for domestic or household purposes shall be classed as residential service. Where electricity service is provided for combined residential and business purposes (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be in the discretion of Bluewater Power Distribution Corporation ("Bluewater Power") and shall be based on such considerations as the estimated predominant consumption or the municipal tax roll classification. A residential customer may be found in a detached, semi-detached, linear row housing, apartment building or mixed-use building. Where more than one dwelling is served by a single meter, that service shall be considered a General Service Customer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13.80
Distribution Volumetric Rate	$/kWh	0.0188
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014		
Applicable only to Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0017)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM)		
Recovery Rate Rider (2011) – effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM)		
Recovery Rate Rider (2012) – effective until April 30, 2014	$/kWh	0.0002
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kWh	(0.0005)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0057

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a customer not designated as Residential, and that over a twelve month period has, or a new customer forecast to have, an average monthly peak demand less than 50 kW, and has a monthly peak demand that never exceeds 100 kW. Bluewater Power shall review this rate class designation on an annual basis and the customer's designated rate class may change as a result. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	23.71
Distribution Volumetric Rate	$/kWh	0.0166
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only to Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0016)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery Rate Rider (2011) – effective until April 30, 2013	$/kWh	0.0001
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery Rate Rider (2012) – effective until April 30, 2014	$/kWh	0.0002
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification applies to a customer not designated as Residential, and that over a twelve month period has, or a new customer forecast to have, an average monthly peak demand equal to or greater than 50 kW and less than 1,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	142.00
Distribution Volumetric Rate	$/kW	3.5617
Low Voltage Service Rate	$/kW	0.0722
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 Applicable only to Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kW	0.4186
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.4464)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery Rate Rider (2012) – effective until April 30, 2014	$/kW	0.0149
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kW	(0.0614)
Retail Transmission Rate – Network Service Rate	$/kW	2.5648
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9998

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a customer not designated Residential, and that: over a twelve month period has, or a new customer forecast to have, an average monthly peak demand equal to or greater than 1,000 kW and less than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	3,121.63
Distribution Volumetric Rate	$/kW	1.2790
Low Voltage Service Rate	$/kW	0.0792
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014		
Applicable only to Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kW	0.5237
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.5105)
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kW	(0.0363)
Retail Transmission Rate – Network Service Rate	$/kW	2.7241
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1923

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0153

LARGE USE SERVICE CLASSIFICATION

This classification applies to a customer not designated as Residential, and that over 12 consecutive billing periods has, or a new customer forecast to have, an average monthly peak demand equal to or greater than 5,000 kW. This rate class designation is reviewed on an annual basis and the customer's designated rate class may change as a result. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24,427.60
Distribution Volumetric Rate	$/kW	1.4610
Low Voltage Service Rate	$/kW	0.0905
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Non-RPP Customers and excluding Wholesale Market Participants	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014		
Applicable only to Non-RPP Customers and excluding Wholesale Market Participants	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kW	0.6579
Not Applicable to Wholesale Market Participants		
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Wholesale Market Participants	$/kW	(0.0530)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.7177)
Not Applicable to Wholesale Market Participants		
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Wholesale Market Participants	$/kW	(0.1377)
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kW	(0.0470)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.0162
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5070

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or a new customer forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by Bluewater Power and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	15.68
Distribution Volumetric Rate	$/kWh	0.0426
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014		
Applicable only to Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kWh	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kWh	(0.0020)
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kWh	(0.0008)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	3.43
Distribution Volumetric Rate	$/kW	22.6299
Low Voltage Service Rate	$/kW	0.0570
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kW	0.4944
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.8027)
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kW	(0.3944)
Retail Transmission Rate – Network Service Rate	$/kW	1.9441
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5783

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.14
Distribution Volumetric Rate	$/kW	16.5512
Low Voltage Service Rate	$/kW	0.0558
Rate Rider for Global Adjustment Sub-Account Disposition (2011) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014		
Applicable only to Non-RPP Customers	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2013	$/kW	0.4212
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014	$/kW	(0.6964)
Rate Rider for Tax Change (2012) – effective until April 30, 2013	$/kW	(0.3152)
Retail Transmission Rate – Network Service Rate	$/kW	1.9342
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5461

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0153

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Bluewater Power Distribution Corp.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0153

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration		
Duplicate invoices for previous billing	$	15.00
Income tax letter	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	10.00
Returned Cheque charge (plus bank charges)	$	15.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – $/per pole/year	$	22.35

Bluewater Power Distribution Corp.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0153

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0356
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0253
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Appendix C

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January 30, 2012

Via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, P.O. Box 2319
Toronto, ON   M4P 1E4

Dear Ms. Walli:

Re: Veridian Connections Inc., 2012 IRM3 Electricity Distribution Rate Application Reply Submission, Board File No.: EB-2011-0199

Veridian Connections Inc. is pleased to submit the enclosed reply to the submissions received from Board staff and the Vulnerable Energy Consumers Coalition ("VECC") on January 16th, 2012.

Please do not hesitate to contact me if you require further information. I can be reached at 905-427-9870, extension 2202 or by email at garmstrong@veridian.on.ca.

Yours truly,

Original signed by

George Armstrong
Manager of Regulatory Affairs and Key Projects

cc Mr. Michael Buonaguro, VECC
Ms. Laurie McLorg, Veridian Connections Inc.

Introduction

Veridian Connections Inc. ("Veridian") filed an application with the Ontario Energy Board (the "OEB" or the "Board") on October 14, 2011, under section 78 of the *Ontario Energy Board Act, 1998,* seeking approval for changes to the distribution rates that Veridian charges for electricity distribution to be effective May 1, 2012. The Application is based on the 2012 3rd Generation Incentive Regulation Mechanism ("IRM3"). The application also included items and methodologies outlined in Chapter 3 of the OEB's Filing Requirements of Transmission and Distribution dated June 22, 2011 (the "Filing Requirements").

On December 1, 2011, Veridian received interrogatories from Board Staff and the Vulnerable Energy Consumers Coalition ("VECC"). On December 15, 2011, Veridian responded to those interrogatories. On January 16, 2012, Veridian received Board Staff's and VECC's submissions pertaining to the Application. Veridian submits this document in response to Board Staff's and VECC's submissions.

Submissions were made by Board Staff and VECC on the following:

- Revenue to Cost Ratio Adjustments
- Account 1521 – Special Purpose Charge ("SPC")
- Disposition of Group 1 Deferral and Variance Accounts
  - Group 1 Account Balances
  - Disposition Period
  - Bill Presentation of the Global Adjustment ("GA") Rate Rider
- Lost Revenue Adjustment Mechanism ("LRAM") Claim

Revenue to Cost Ratio Adjustments

In section 2.8 of its submission, VECC notes that no amount was entered for revenue offsets related to Veridian's last COS application on Sheet 7 of the 2012 IRM Revenue to Cost Ratio Adjustment Workform. VECC goes on to reference interrogatories and interrogatory responses from Veridian's 2011 proceeding on this issue. In response to the 2011 interrogatory, Veridian explained that the Revenue to Cost ratios proposed by Veridian in its 2010 Cost of Service Rate Application (and agreed to in the Settlement Agreement approved by the Board) were derived from the Distribution Revenue Requirement (Total Service Revenue Requirement less Revenue Offsets), thus it was appropriate to omit Revenue Offsets from the Board issued Workforms for the 2011 Revenue to Cost Ratio Adjustments. On page 9 of the Manager's Summary in its 2012 IRM Application, Veridian offered this same rationale to explain why no amount had been included for revenue offsets in the 2012 workform.

Also, as requested in response to a 2011 VECC interrogatory, Veridian provided an allocation of the approved Revenue Offsets for 2010 between its two tariff zones on the same basis as the overall 2010 Revenue Requirement was assigned within its 2010 COS application.

Subsequently in its reply submission in the 2011 proceeding VECC stated:

"Subsequent to receiving the IR responses VECC has reviewed the 2010 rate Application and Draft Rate Order filed by Veridian. It is VECC's understanding from this review that the Revenue to Cost ratios as derived by Veridian in its original Application and agreed to in the Settlement Agreement approved by the Board were derived using the Base Distribution Revenue Requirement. If this is the case, then the approach initially used by Veridian in the current application is correct. VECC invites Veridian to clarify this matter in its Reply."

In its Reply in the 2011 proceeding Veridian stated:

"The second issue concerned the omission of Revenue Offsets in the Board issued Workforms. Veridian provided explanation of this omission in its response to Board Interrogatory 7 and specifically noted that the Revenue to Cost ratios derived by Veridian in its 2010 Cost of Service Rate Application and agreed to in the Settlement Agreement approved by the Board were derived from the Distribution Revenue Requirement (Total Service Revenue Requirement less Revenue Offsets), thus it was appropriate to omit Revenue Offsets from the Board issued Workforms. In its Final Argument submission (paragraph 2.3, page 2), VECC indicates that after a review of Veridian's 2010 rate Application and Draft Rate Order, it does understand Veridian's statement on this issue to be correct. As well, VECC goes on to state that "If this is the case, then the approach initially used by Veridian in the current application is correct." Veridian acknowledges that VECC now accepts Veridian's initial approach of omitting Revenue Offsets in the Board issued Workforms as correct and submits that no further adjustments to the Workforms are required."

Veridian further notes that the Board, in its decision dated April 7, 2011 accepted Veridian's proposed Revenue to Cost Ratio adjustments based on its original filing with no amounts included for Revenue Offsets in the Workforms.

In section 2.9 of its submission in the current 2012 proceeding VECC submits that the 2012 workform should be revised to include information on revenue offsets based on the methodology it proposed and then subsequently abandoned in the 2011 proceeding.

Veridian submits that the request to incorporate this revision for 2012 rates would serve no purpose as Veridian's current treatment of Revenue Offsets within the Revenue to Cost Ratio Adjustment workform is the same as that agreed to by VECC and accepted by the Board in the 2011 proceeding.

Account 1521 – Special Purpose Charge ("SPC")

On page 20 of its 2012 IRM3 Distribution Rate Application, Veridian stated that the unrecovered principal balance in the SPC Account 1521 was $56,013. In response to Board interrogatory #10, Veridian provided the table below (Table 1).

Subsequently, through a year-end review process, Veridian has determined that incorrect information regarding the amounts refunded to customers was used for the calculation of the outstanding principal balance and the amounts to be refunded was overstated. However, the correct amounts were actually refunded to customers.

Table 2 below is an update of Table 1 and reflects the correct amount refunded to customers, updated forecast carrying charges and the final SPC balance for disposition. The amount refunded to customers that were charged in error has been updated from $185,213 to $110,293. The corrected principal balance is an over recovery of $18,928 and the final SPC balance for disposition is a credit of $14,251.

Table 1 – From Response to Board Staff Interrogatory #10

SPC Assessment (Principal balance)	Amount recovered from customers in 2010	Carrying Charges for 2010	Dec 31, 2010 Year End Principal Balance	Dec 31, 2010 Year End Carrying Charges Balance	Amount recovered from customers in 2011	Amt refunded to customers that were charged in error	Forecasted Dec 31, 2011 Year End Principal Balance	Forecasted Apr 30, 2012 Carrying Charges Balance	Total for Disposition (Principal & Carrying Charges)
$977,264	$461,827	$3,324	$515,437	$3,324	$644,742	$185,213	$56,013	$6,179	$62,192

Table 2 – Table 1 revised with corrected Amount refunded to Customers

SPC Assessment (Principal Balance)	Amt Recovered from customers in 2010	Carrying Charges for 2010	Dec 31,2010 Yr End Principal Balance	Dec 31,2010 Yr End Carrying Charges Balance	Amt Recovered from customer in 2011 (June 1st, 2011 - Aug 16, 2011)	Amt refunded to customers that were charged in error	Forecasted Dec 31, 2011 Yr End Principal Balance	Forecasted Apr 30, 2012 Carrying Charges Balance	Total for Disposition (Principal & Carrying Charges)
$977,264	$461,827	$3,324	$515,437	$3,324	$644,659	$110,293	-$18,928	$4,677	-$14,251

The updated final SPC balance for disposition has been allocated to the Veridian-Main and Gravenhurst tariff zones on the same basis as was previously employed. Table 3 below shows this allocation.

Table 3 - Allocation of SPC 1521 Balance to Veridian Main and Gravenhurst		
Principal Balance	(18,929.75)	
Volume	**kWh**	**% Allocation**
Veridian Main	2,522,511,100	96.14%
Gravenhurst	101,329,682	3.86%
Total volume	2,623,840,782	100.00%
Allocation of Principal Balance		
Veridian Main	(18,198.71)	
Gravenhurst	(731.04)	
	(18,929.75)	

The total SPC principal and interest to April 30th, 2012 for Veridian Main and Gravenhurst respectively is $(13,701) and $(550).

Veridian notes that when the IRM Rate Generator models for both Veridian-Main and Gravenhurst are updated with the new balances for Account 1521 – SPC, Deferral and Variance Rate Riders change for some of the rate classes. The changes are provided in Tables 4 and 5.

Table 4 – Changes in Variance/Deferral Rate Riders - Veridian Main

Rate Class	Original Variance/Deferral Rate Rider	Updated Variance/Deferral Rate Rider	Diff	%
Residential per kWh	($0.0035)	($0.0035)	$0.0000	0.00%
GS < 50 kW per kWh	($0.0035)	($0.0035)	$0.0000	0.00%
GS > 50 kW per kW	($1.3300)	($1.3360)	($0.0060)	0.45%
Intermediate Use per kW	($1.2904)	($1.2962)	($0.0058)	0.45%
Large Use per kW	($1.8452)	($1.8535)	($0.0083)	0.45%
Unmetered Scattered Load per kWh	($0.0035)	($0.0035)	$0.0000	0.00%
Sentinel Lighting per kW	($1.2416)	($1.2471)	($0.0055)	0.45%
Street Lighting per kW	($1.2347)	($1.2402)	($0.0055)	0.45%

Table 5 – Changes in Variance/Deferral Rate Riders - Gravenhurst

Rate Class	Original Variance/Deferral Rate Rider	Updated Variance/Deferral Rate Rider	Diff	%
Residential-Urban per kWh	($0.0039)	($0.0039)	$0.0000	0.00%
Residential-Suburban-Year Round per kWh	($0.0039)	($0.0039)	$0.0000	0.00%
Residential-Suburban-Seasonal per kWh	($0.0039)	($0.0039)	$0.0000	0.00%
GS < 50 kW per kWh	($0.0039)	($0.0039)	$0.0000	0.00%
GS > 50 kW per kW	($1.6159)	($1.6227)	($0.0068)	0.42%
Sentinel Lighting per kW	($1.3930)	($1.3988)	($0.0058)	0.42%
Street Lighting per kW	($1.3330)	($1.3386)	($0.0056)	0.42%

Disposition of Group 1 Deferral and Variance Accounts as per the EDDVAR Report

(i) Group 1 Account Balances

In its submission, Board Staff references tables that were provided by Veridian in its response to Board Staff interrogatory # 13. The tables provided information on adjustments to various Group 1 account balances related to 2010, and that were identified subsequent to Veridian's 2010 year end RRR filings. Further, Board Staff noted that they are unable to reconcile various amounts in the tables and requested that Veridian provide an updated table with the adjustments to Account 1588 (including the global adjustment sub-account), including principal and carrying charges, and also provide an updated calculation of the preset disposition threshold for the Group 1 account balances for both service areas.

Veridian acknowledges that some of the amounts provided in response to Board Staff interrogatory # 13 were in error. Veridian has provided the corrected requested information in the tables below.

Table 6 – Corrections to Account 1588 – Veridian Main

Account	Amount of Adjustment	Principal Balance as Filed	Resulting Principal Balance after Adjustment	Resulting Carrying Charges after Adjustment	Resulting Balance for Disposition after Adjustment
1588 – RSVA-Power (excluding Global Adjustment)	$6,127,096	($15,043,797)	($8,916,701)	($261,693)	($9,178,394)
1588-RSVA-Power-Sub Account-Global Adjustment	($1,910,724)	$7,143,369	$5,232,645	$209,739	$5,442,384

Updated Calculation of Threshold Test – Main

Updated Total Claim for Threshold Test (All Group 1 Accounts)	($4,764,273)
Threshold Test – Total Claim per kWh	(0.00201)

Table 7 – Corrections to Account 1588 - Gravenhurst

Account	Amount of Adjustment	Principal Balance as Filed	Resulting Principal Balance after Adjustment	Resulting Carrying Charges after Adjustment	Resulting Balance for Disposition after Adjustment
1588 – RSVA-Power (excluding Global Adjustment)	$194,969	($551,256)	($356,287)	($6,433)	($362,720)
1588-RSVA-Power-Sub Account-Global Adjustment	($59,801)	$130,101	$70,300	$4,133	$74,433

Updated Calculation of Threshold Test – Gravenhurst

Updated Total Claim for Threshold Test (All Group 1 Accounts)	($431,196)
Threshold Test – Total Claim per kWh	(0.00476)

The adjustments were due to formula errors identified in Veridian's spreadsheet calculations of the Regulated Price Plan and Global Adjustment Settlement Amounts with the IESO for a period in 2010. These errors were identified through a review conducted by the Ministry of Finance of Veridian's records supporting monthly requests to the IESO under the Regulated Price Plan. The adjustments pertained to periods in 2010 and 2011 and were not finalized until late August 2011. The adjustments were included in the September IESO submission and the September settlement amount. The full adjustment amount was recorded to the appropriate accounts in September 2011.

Board Staff has raised concerns that Veridian did not attempt to amend its 2010 RRR filings with the adjustments.

At the time of the adjustment it was unclear to Veridian whether a restatement of its 2010 YE RRR Filing was appropriate. Even though a portion of the total adjustment amount pertained to a period in 2010, the adjustment was not settled with the IESO until 2011. In retrospect, Veridian agrees that it would have been appropriate to request restatement of the 2010 YE RRR Filings to include the 2010 portion of the September 2011 adjustment (the amounts noted in the tables above).

On this basis and for rate stability, Veridian submits that it is appropriate for the Board to include the adjustments to the balances of Account 1588 proposed for disposition. If the adjustments are not made, the amounts refunded for Account 1588 (excluding Global Adjustments) during the 2012 rate year would be overstated, leading to subsequent recovery from ratepayers during a future rate year. Similarly, larger amounts would be recovered for Account 1588-sub Account Global Adjustment now and then refunded in a future rate year.

As can be seen from the results of the updated threshold test calculations, the materiality threshold of $0.001/kWh set for triggering disposition would still be met when including the adjustments.

(ii) Disposition Period

Veridian notes that in its submission, Board staff agrees with Veridian's proposal of a two year disposition period on the basis that it would strike a balance between reducing intergenerational inequity and mitigating rate volatility. Board staff also state that they agree with the two year disposition period *"Regardless of whether the Board approves the inclusion of the adjustments to account 1588 referenced above …"*

Veridian notes that VECC has raised no concerns or objections to Veridian's proposed two-year disposition period.

(iii) Bill Presentation of the Global Adjustment ("GA") Rate Rider

Veridian has proposed to dispose of the GA sub-account by means of a separate rate rider applicable to non-RPP customers and presented as part of the electricity component of the bill. In its submission, Board staff note that the prevalent practice among distributors is to present GA rate riders as part of the delivery component of the bill, and suggests that the Board consider directing Veridian to do the same.

With the Board's approval, Veridian has been presenting its GA rate riders as part of the electricity component of its bills for the past two years. This practice was first established in 2010 through Veridian's 2010 cost of service proceeding (EB-2009-0140) and was again accepted in 2011 through Veridian's 2011 IRM rate proceeding (EB-2010-0117).

Veridian submits that continuing its current practice of presenting its GA rates riders as part of the electricity component of bills offers the benefit of consistency with past practice, and would thereby reduce the potential for customer confusion. However, Veridian does have the capability of presenting the charge under the delivery component of the bill, and would not object to this treatment if so directed by the Board.

Lost Revenue Adjustment Mechanism ("LRAM") Claim

2007-2009 Lost Revenues

Both Board Staff and VECC support the approval of the 2007, 2008 and 2009 lost revenues requested by Veridian.

2010 Programs and Persisting Impacts of 2005-2010 Programs

Neither Board Staff nor VECC support Veridian's requested recovery of an LRAM amount that includes the effect of new 2010 programs as well as persistence for 2005-2009 programs in 2010. The basis for Board Staff and VECC's arguments on this issue is the Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "Guidelines" or "2008 Guidelines") issued on March 28, 2008. Specifically, Board Staff and VECC are relying on section 5.2 of the Guidelines, which provide:

"Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time."

Board Staff and VECC's arguments disregard the most important piece of evidence that is relevant to the determination of this issue - the settlement agreement reached in Veridian's 2010 rate proceeding (EB-2009-0140) (the "Settlement Agreement"), which provides:

> *3 b. Is the impact of CDM initiatives suitably reflected in the load forecast?*
> *Complete Settlement: Veridian has not included any CDM program impacts in the 2010 load forecast as details regarding Ontario Power Authority programs in the test year were not available at the time that the load forecast was prepared. For the purpose of obtaining complete settlement of all issues, the Parties agree that this treatment is appropriate.*

Evidence: *N/A*
Supporting parties: *VCI, SEC, EP, CCC, and VECC*
Parties taking no position: *None.*
Opposing parties: *None*

Although the Guidelines contemplate that CDM initiatives would be factored into a load forecast in a cost of service application, the parties in Veridian's 2010 cost of service application specifically agreed to exclude CDM initiatives from Veridian's forecast because "details regarding Ontario Power Authority programs in the test year were not available at the time that the load forecast was prepared." Therefore, the parties (including VECC) agreed to depart from the methodology contemplated by the Guidelines due to the lack of available information. Board Staff was involved in the settlement negotiation. Had Board Staff been concerned about the departure from the methodology contemplated by the Guidelines, Board Staff should have raised this concern with the Board. However, Board Staff raised no concerns, and the Board accepted the Settlement Agreement in its Decision dated March 31, 2010.

Veridian submits that it is inappropriate for Board Staff and VECC to argue in this proceeding that Veridian should effectively be penalized for not following the methodology contained in the Guidelines, in light of the fact that there is a final Board decision that accepts Veridian's departure from the methodology contemplated by the Guidelines as appropriate.

Further, both Board Staff and VECC relied on the Board's decision in EB-2011-0174 (Whitby Hydro) in support of their arguments. Board staff noted that:

"...in its Decision and Order in the EB-2011-0174 proceeding, the Board disallowed LRAM claims for the rebasing year as well as persistence of prior year programs in and beyond the test year on the basis that these savings should have been incorporated into the applicant's load forecast at the time of rebasing."

Veridian submits that its circumstances are distinguishable from those in the Whitby Hydro proceeding, because Whitby Hydro's settlement agreement did <u>not</u> specifically address the exclusion of CDM impacts from the load forecast. As discussed above, Veridian's Settlement Agreement did, so the parties specifically agreed to depart from the methodology contained in the Guidelines, and the Board accepted that departure. Therefore, Veridian submits that the Board's decision in EB-2011-0174 is not applicable to Veridian's circumstances, and should not influence the Board in this proceeding.

Board staff also suggested in its submission that if Veridian had expected to file an LRAM application to be compensated for CDM impacts not included in its load forecast, Veridian should have highlighted that expectation in the Settlement Agreement. Veridian submits that Board Staff's suggestion should not be accepted by the Board for the following two reasons:

i) Board Staff seems to be relying on the January 5, 2012 *Guidelines for Electricity Distributor Conservation and Demand Management* (the "2012 CDM Guidelines"), which state:

> *"In the situation where the distributor has not included CDM impacts in its load forecast, the distributor is expected to make it clear in their rate application that CDM impacts have not been included, why they have not been included* ***and whether the distributor intends to address CDM impacts through an LRAM****."* [emphasis added]

> The emphasized wording from the 2012 CDM Guidelines set out above are not found in the 2008 Guidelines. Therefore, Board Staff is suggesting that the Board retroactively impose a requirement that did not exist at the time Veridian entered into the Settlement Agreement.

> ii) Veridian's expectation of future recovery can easily be inferred from the Settlement Agreement, since the stated reason for omitting CDM impacts from the 2010 load forecast was "lack of available information". In other words, Veridian did not possess CDM impact information for its load forecast <u>at the time</u>. It logically follows that once the necessary information became available, Veridian would use it to address CDM impacts in the 2010 Test Year. Veridian never agreed to forego its lost revenues related to its 2010 CDM programs, and there is nothing in the Settlement Agreement to suggest that it did.

For these reasons, Veridian submits that it should be permitted to recover an LRAM amount that includes the effect of new 2010 programs as well as persistence for 2005-2009 programs in 2010, subject to an adjustment related to information provided in Veridian's response to Board Staff interrogatory #14.

In preparing the response to Board staff interrogatory #14, Veridian realized that its load forecast did include some CDM impacts related to programs delivered in prior years. Veridian`s load forecast was prepared using a regression model that projected 2010 sales volumes based on an historic dataset of wholesale power deliveries from May 2002 to December 2008. Since Veridian did deliver CDM programs during the period of time covered by this dataset, some historical savings were captured and projected into the test year.

However, Veridian submits that these implicit savings in its 2010 load forecast were significantly less than the actual 2010 impact of its 2005 to 2010 CDM programs. This view is based on the fact that only about the latter half of the historic dataset used for the load forecast covered periods of CDM program activity, and that the CDM impacts during this time were not significant since CDM programs were in the process of being re-established in the province following a long period of dormancy.

To confirm this view, Veridian carried out an analysis which was thoroughly detailed in its response to Board Staff interrogatory #14. The analysis showed that Veridian's approved 2010 load forecast included approximately 22% of the 2010 impacts of Veridian's 2005 to 2010 CDM programs. Veridian proposes that its original LRAM amount be reduced to account for this circumstance, as set out in the updated LRAM information provided in the following section.

Response to Board Staff Submission Request

In their submission, Board staff had requested that Veridian provide an updated LRAM amount that only includes lost revenues from 2007-2009 and the associated rate riders. Veridian has provided this in table 8 below.

Table 8: Lost Revenue and Rate Riders for a 2007 – 2009 LRAM Claim

	Total Lost Revenue (2007 - 2009)		2010 Billed kWh	kW	Rate Rider 1 Year		
Residential	$	652,268	972,134,187		$	0.0007	/kWh
GS<50	$	118,071	303,108,577		$	0.0004	/kWh
GS>50	$	48,952		2,409,333	$	0.0203	/kW
Large Use	$	3,671		387,405	$	0.0095	/kW
	$	**822,961**					

However, if the intention of this request was to determine what Veridian's lost revenue would be for the period prior to its 2010 load forecast, then Veridian believes that Board staff's request should include the first four months of 2010 as Veridian was still under IRM at this time. Although Veridian does not agree with the approach being suggested by Board staff, it believes that if the Board finds Veridian to be ineligible for LRAM after rebasing, then at a minimum the lost revenue being recovered should include up until the date of rebasing, May 1, 2010. Table 9 takes into consideration the Board staff request and includes the first four months of 2010:

Table 9: Lost Revenue and Rate Riders for a 2007 – April 30, 2010 LRAM Claim

	Total Lost Revenue (2007 - Apr 30, 2010)		2010 Billed kWh	kW	Rate Rider 1 Year		
Residential	$	757,270	972,134,187		$	0.0008	/kWh
GS<50	$	169,472	303,108,577		$	0.0006	/kWh
GS>50	$	67,554		2,409,333	$	0.0280	/kW
Large Use	$	5,326		387,405	$	0.0137	/kW
	$	**999,623**					

Despite providing the requested information above, Veridian maintains that it should be awarded the full LRAM amount of $1,389,688 for lost revenues in the years 2007-2010. Veridian is also willing to accept a discounted 2010 LRAM amount to account for the effects of conservation that were unintentionally included in its 2010 load forecast as mentioned above. Discounting lost revenues from May 1, 2010 to December 31, 2010 by 22% would decrease Veridian's LRAM claim to $1,303,874. These two positions are depicted in Tables 10 and 11 below:

Table 10: Lost Revenue and Rate Riders for a 2007 – 2010 LRAM Claim

	Total Lost Revenue (2007-2010)	2010 Billed (1) kWh	kW	Rate Rider 1 Year	
Residential	$ 986,742	972,134,187		$ 0.0010	/kWh
GS<50	$ 288,771	303,108,577		$ 0.0010	/kWh
GS>50	$ 106,765		2,409,333	$ 0.0443	/kW
Large Use	$ 7,411		387,405	$ 0.0191	/kW
	$ 1,389,688				

Table 11: Lost Revenue and Rate Riders for a 2007 – 2009, and discounted 2010 LRAM Claim

	Total Lost Revenue (2007 - 2009, discounted 2010)	2010 Billed kWh	kW	Rate Rider 1 Year	
Residential	$ 936,258	972,134,187		$ 0.0010	/kWh
GS<50	$ 262,525	303,108,577		$ 0.0009	/kWh
GS>50	$ 98,138		2,409,333	$ 0.0407	/kW
Large Use	$ 6,952		387,405	$ 0.0179	/kW
	$ 1,303,874				

Veridian would like to take this opportunity to advise the Board that it intends to file for recovery of unclaimed lost revenues up to and including its next rebasing (January 1, 2011 to April 30, 2014) in a future LRAM application.

All of which is respectfully submitted this 30th day of January 2012

Appendix D

Interrogatories Pertaining to Both Gravenhurst and Main Service Areas

LRAM

14. Ref: Manager's Summary, pg. 22-29

Veridian has requested recovery of $1,388,731, which includes $52,442 in carrying charges, related to new lost revenues from CDM programs delivered from 2007-2010 and persisting lost revenues relating to programs delivered from 2005-2007.

Veridian noted that its electricity distribution rates were established on a cost of service basis for 2010 and that the approved distribution rates were based on a load forecast that excluded the impacts of CDM programs. The CDM provision of the load forecast formed part of a settlement agreement that was accepted by the Board.

Request

a) Please provide the rationale for why Veridian's last load forecast excluded the impacts of CDM programs.

Response:

a) When preparing its 2010 cost of service rate application and accompanying test year load forecast, Veridian was guided by the Board's May 27, 2009 Chapter 2 Filing Requirements for Transmission and Distribution Applications. These were the filing guidelines in force at that time, and they did not stipulate that a distributor must include the effects of CDM within its load forecast.

   The exclusion of CDM impacts from the load forecast was acknowledged and accepted by all parties to the settlement agreement reached in Veridian's 2010 rate proceeding (EB-2009-0140). This settlement agreement was accepted by the Board in its Decision dated March 31, 2010. Following is the relevant excerpt from the agreement:

   > ***3 b.*** *Is the impact of CDM initiatives suitably reflected in the load forecast?*
   >
   > ***Complete Settlement****: Veridian has not included any CDM program impacts in the 2010 load forecast as details regarding Ontario Power Authority programs in the test year were not available at the time that the load forecast was prepared. For the purpose of obtaining complete settlement of all issues, the Parties agree that this treatment is appropriate.*
   > ***Evidence****: N/A*

***Supporting parties**: VCI, SEC, EP, CCC, and VECC*
***Parties taking no position**: None.*
***Opposing parties**: None*

Veridian clearly did not explicitly include in its 2010 load forecast, projected CDM savings related to forecast CDM program activity in its 2010 test year. However, in preparing this interrogatory response it has concluded that its load forecast did include some CDM impacts related to programs delivered in prior years. Veridian`s load forecast was prepared using a regression model that projected 2010 sales volumes based on an historic dataset of wholesale power deliveries from May 2002 to December 2008. Since Veridian did deliver CDM programs during the period of time covered by this dataset, some historical savings would have been captured and projected into the test year.

However, Veridian submits that these implicit savings in its 2010 load forecast were significantly less than the actual 2010 impact of its 2005 to 2010 CDM programs. This view is based on the fact that only about the latter half of the historic dataset used for the load forecast covered periods of CDM program activity, and that the CDM impacts during this time were not significant since CDM programs were in the process of being re-established in the province following a long period of dormancy.

To confirm and exhibit this view, Veridian has carried out the following analysis:

1. The 2002 – 2008 dataset used for the 2010 load forecast has been adjusted by adding the wholesale impacts of CDM program savings recorded during these years.

2. The regression model used for Veridian`s 2010 load forecast has been re-run using this revised dataset.

3. The adjusted 2010 forecast based on the use of the revised dataset has been compared to the approved 2010 forecast. The difference between the two forecasts identifies the CDM impacts implicit in Veridian`s approved 2010 forecast.

4. The retail impact of the CDM savings found to have been implicitly included in Veridian`s 2010 load forecast are compared to the 2010 impacts of Veridian`s 2005 to 2010 CDM programs.

This analysis shows that Veridian`s approved 2010 load forecast included approximately 22% of the 2010 impacts of Veridian`s 2005 to 2010 CDM programs. Details supporting this determination are provided in Attachment E.

Attachment E:

2010 Load Forecasting Methodology

For its 2010 Cost of Service Application (EB-2009-0140) Veridian retained Elenchus Research Associates (ERA) to prepare 2010 weather normalized load forecasts. The load forecast methodology was based on monthly wholesale deliveries to the distribution system from May 2002 to December 2008. Monthly wholesale forecasts were developed for each of Veridian's tariff zones – Main and Gravenhurst. Allocations of the monthly wholesale energy forecast were then allocated to individual classes.

Veridian's load forecasting methodology and resulting load forecast for 2010 were agreed upon within the Settlement Agreement and accepted by the Board.

A copy of the ERA Load Forecasting Report as filed within EB-2009-0140 has been included as Attachment F and can be referred to for detailed information such as the historic data sets used, the equations resulting from the multiple regression analysis, weather normalization etc.

Adjustments to the Historic Wholesale Data Sets

The table below outlines the annual kWh savings identified by Veridian in its 2009 IRM Application (EB-2008-0150) and in its current application (EB-2011-0199) in LRAM Attachments 2 and 7 for the period 2005 to 2008.

Table 1: Annual kWh savings

Type of Program	2005	2006	2007	2008
Third-Tranche Funded (claimed in EB-2008-0150)-included persistence to 2007	1,817,235	13,349,533	614,033	N/A
Third-Tranche Persistence-for 2005 - 2007 in 2008 (Attachment 2-EB-2011-0199)				283,758 6,023,970 639,726
OPA Funded Programs	N/A		5,624,124	5,527,154
OPA Persistence of 2007 in 2008 (Attachment 2-EB-2011-0199)				5,586,710
Totals by Year	**1,817,235**	**13,349,533**	**6,238,157**	**18,061,318**

Attachment E

Veridian acknowledges that the kWh savings above would necessarily not be included within the actual wholesale energy deliveries used to determine Veridian's 2010 wholesale load forecast.

In order to quantify the impact of these kWh savings, Veridian has produced an adjusted wholesale 2010 load forecast using the exact same methodology as used in EB-2009-0140 and adjusting the historic data set of actual wholesale energy deliveries by adding the kWh savings for each year as identified in Table 1 above.

The annual kWh savings are not identified separately between the Main and Gravenhurst tariff zones and so must be apportioned. The kWh savings were apportioned on the basis of the proportion of the actual annual wholesale deliveries between the two tariff zones. Then, the annual amounts were allocated to the months based on the proportions of the actual kWh deliveries within that calendar year. The monthly volumes allocated are retail kWh and in order to add these amounts to wholesale volumes, they were uplifted by the Total Loss Factor applicable to each tariff zone in each month of the period January 2005 – December 2008.

The regression analysis was then re-run using the adjusted actual data set for the dependent variable of wholesale energy deliveries (actuals plus annual kWh savings). The values of the explanatory variables such as Heating and Cooling Degree Days, Full-Time Employment measures in Ontario and Peak Days were left unchanged.
The resulting adjusted equations for each tariff zone are displayed below:

Main
R Square – 0.894846567
Adjusted R Square – 0.889238384

	Coefficients
Constant	-86,508,456.705
HDD	81,883.464
CDD	312,432.023
Peakdays	1,825,063.898
FTE_Ont	42,027.609

Attachment E

Gravenhurst
R Square – 0.938693156
Adjusted R Square – 0.935423458

	Coefficients
Constant	-5,904,179.27
HDD	5,749.66
CDD	32,442.89
Month Days	247,905.31
FTE_Ont	746.89

When compared with the equations within the ERA report for the approved 2010 load forecast (pages 5 and 17), it can be seen that the R square and adjusted R square values, as well as the values of the coefficients of the explanatory variables do not vary significantly.

The adjusted equations were then used to forecast the 2010 wholesale energy deliveries using the same methodology and explanatory variable data as was used in the Board approved methodology as outlined in the ERA report.

The table below shows the approved and adjusted 2010 wholesale energy deliveries by tariff zone.

Table 2: 2010 Wholesale Load Forecast – Approved and Adjusted

	Approved 2010 Load Forecast - wholesale	**Adjusted 2010 Load Forecast - wholesale**	**%age Increase**	**kWh Increase - Wholesale**	**TLF**	**kWh Increase - Retail**
Main	2,516,710,137	2,525,097,545	0.33 %	8,387,408	1.0442	8,032,377
Gravenhurst	99,133,900	99,471,338	0.34 %	337,438	1.1013	306,400
		Increase in kWh		8,724,846		8,338,777

As stated previously, the annual kWh savings identified are retail kWh. In order to measure the above calculated increase in wholesale kWh as a percentage of the retail kWh annual savings, the wholesale values must be adjusted to retail by dividing by the Total Loss Factor applicable for each tariff zone in 2010.

Attachment E

The table below shows the total 2010 kWh savings included within Veridian's current LRAM claim

Table 3: Total 2010 kWh Savings Claimed

2005	3rd Tranche	283,758
2006	3rd Tranche	6,023,970
2007	3rd Tranche	639,726
	OPA	4,060,683
2008	OPA	5,164,832
2009	OPA	16,057,470
2010	OPA	5,677,883
	Total	**37,908,320**

The retail impact of the CDM savings implicitly included within Veridian's 2010 load forecast is 8,338,777 kWh or 22.0% of the 2010 impacts of Veridian's 2005 to 2010 CDM programs.

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Veridian Connections Inc.

May 25, 2009

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Veridian Connection Inc.'s (VCI) rebasing rate application for 2010 rates. A weather normal load forecast is developed for the bridge year (2009) and test year (2010) and weather normalized historical consumption is also derived.

VCI currently has two separate rate schedules. The Veridian Main system (consisting of service areas including Ajax, Belleville, Brock, Clarington, Pickering, Port Hope, Scugog and Uxbridge) and the Gravenhurst system. Therefore, a weather normalized load forecast for each of these service areas needs to be developed.

There are several constraints with respect to data availability that had to be considered when developing the load forecast methodology and process for VCI. One issue is that most customers in the Veridian Main system are billed on a quarterly basis. As a result, it is not possible to accurately estimate monthly class specific consumption. Therefore, the load forecast for VCI's main system is based on monthly wholesale deliveries to the Distribution System from May 2002 to December 2008 as measured at the wholesale point of delivery. While it may be desirable to isolate demand determinants related to individual rate classes, this is simply not possible with the data available for VCI at this time.

The Gravenhurst service area has an additional complication. Most Gravenhurst customers are billed on a bi-monthly basis and monthly class specific consumption is not available. Additionial complications arise as Gravenhurst has three separate Residential rate classes: Residential – Urban, Residential – Sub-Urban, and Residential – Seasonal. While monthly wholesale deliveries are available for the Gravenhurst service area, it would be unrealistic to assign a similar weather corrected consumption pattern to a seasonal customer rate class and a non-seasonal customer class. Therefore, a decision was made to use the weather normalized class throughput for 2004 derived for Gravenhurst by Hydro One Networks for the OEB's Cost Allocation

Informational Filing to forecast the seasonal rate class. From the 2004 weather normalized class throughput, class specific normalized average use per customer (NAC) is derived and used to project weather normal consumption for the bridge year and test year. For other weather sensitive classes, we have used the same methodology as used for VCI – Main.

We note that the OEB has approved both these methodologies previously (i.e., normalizing wholesale purchases and allocating to individual classes based on historical shares and the NAC approach based on previous work done for the Cost Allocation Informational Filing). Therefore, the approaches being adopted here are neither new nor novel, and have been tested and approved in other rate rebasing proceedings.

2 VERIDIAN MAIN

This section outlines the load forecast for the Veridian Main system

2.1 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

The following table outlines monthly wholesale deliveries from May 2002 to December 2008.

Table 1: Monthly Actual Energy (kWh), Veridian Main

	2002	2003	2004	2005	2006	2007	2008
January		228,072,459	235,490,156	233,068,202	229,069,544	235,099,724	230,260,337
February		205,071,925	208,369,155	202,953,097	212,537,640	224,098,670	218,733,112
March		207,225,786	209,294,667	213,421,625	222,589,060	223,513,915	219,617,553
April		187,449,570	187,804,230	185,422,180	188,638,340	199,529,738	192,173,797
May	183,254,394	179,550,481	183,209,950	186,613,649	197,584,849	194,458,410	188,679,252
June	188,410,816	184,906,238	183,040,381	218,021,442	213,143,790	214,003,885	205,832,488
July	219,729,916	200,272,254	196,881,824	234,687,559	239,085,239	217,236,567	224,258,704
August	215,808,113	201,291,286	197,035,444	226,837,472	228,000,091	227,134,590	213,496,237
September	195,012,178	184,407,204	188,313,943	201,266,331	194,232,463	195,954,927	200,053,204
October	187,794,758	188,281,237	184,707,661	197,040,911	204,360,356	196,760,257	199,159,166
November	193,230,765	194,302,491	195,753,579	206,898,914	207,947,135	206,385,785	206,086,069
December	211,583,287	212,485,534	223,114,091	232,485,746	221,161,912	228,329,482	228,433,560
Annual		**2,373,316,465**	**2,393,015,080**	**2,538,717,128**	**2,558,350,419**	**2,562,505,950**	**2,526,783,479**
% change			***0.8%***	***6.1%***	***0.8%***	***0.2%***	***-1.4%***

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For VCI Main, we have used monthly HDD and CDD as reported at Pearson International Airport near Toronto.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for Ontario, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054816). Ontario was chosen, as the VCI Main service territory spans several regional areas (Durham Region, within Toronto CMA, Oshawa CMA, and outside any CMA; Port Hope [Northumberland County]; Belleville [Hastings County]).

The number of peak days (non-holiday week days) is also included as an explanatory variable. For holidays, we have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November.

The historical data for peak days and monthly full-time employment are displayed in *Table 2* below.

Table 2
Peak Days

	2002	2003	2004	2005	2006	2007	2008
January	22	21	21	20	21	22	22
February	20	20	20	20	20	20	20
March	20	21	23	21	23	22	21
April	21	20	20	21	18	19	20
May	22	21	20	21	22	22	21
June	20	21	22	22	22	21	21
July	22	22	21	20	20	22	22

August	21	20	21	22	22	22	20
September	20	21	21	21	20	19	21
October	22	22	20	20	21	22	22
November	21	20	22	22	22	22	20
December	20	21	21	20	19	19	21
	Ontario Full-time Employment ('000s) – CANSIM v2054816						
January	4764.5	4929.6	5048.8	5071.8	5219.1	5259.7	5356.9
February	4733.3	4911.6	5035.5	5043.8	5181.8	5224.7	5335.7
March	4728.5	4911.1	5022.8	5012.8	5153	5205.9	5310.9
April	4766.7	4940.2	5053.9	5065.6	5184.7	5233.8	5341.6
May	4844.3	4995.5	5113.7	5147.2	5290.7	5315.8	5399.9
June	4925.4	5068.9	5218.7	5264.7	5401.1	5426.4	5485.7
July	5038.7	5158.7	5307.2	5369.3	5511	5548.7	5559.3
August	5125	5227	5366.9	5443.4	5550.7	5615.9	5616.2
September	5114.2	5196.7	5319.8	5425.9	5500.2	5579	5580.3
October	5049.3	5147.7	5244	5370.8	5421.1	5515.2	5537.1
November	4964.8	5078.7	5156.2	5287.8	5326.2	5432.8	5433.4
December	4953.4	5076.7	5125.6	5267.3	5309.4	5409.3	5393.6
Annual Avg	***4917.3***	***5053.5***	***5167.8***	***5230.9***	***5337.4***	***5397.3***	***5445.9***
Ann % chg	***1.0%***	***2.8%***	***2.3%***	***1.2%***	***2.0%***	***1.1%***	***0.9%***

Using these data, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual energy deliveries and the explanatory variables.

The resulting equation, estimated using the 80 observations from 2002:05-2008:12 is displayed below:

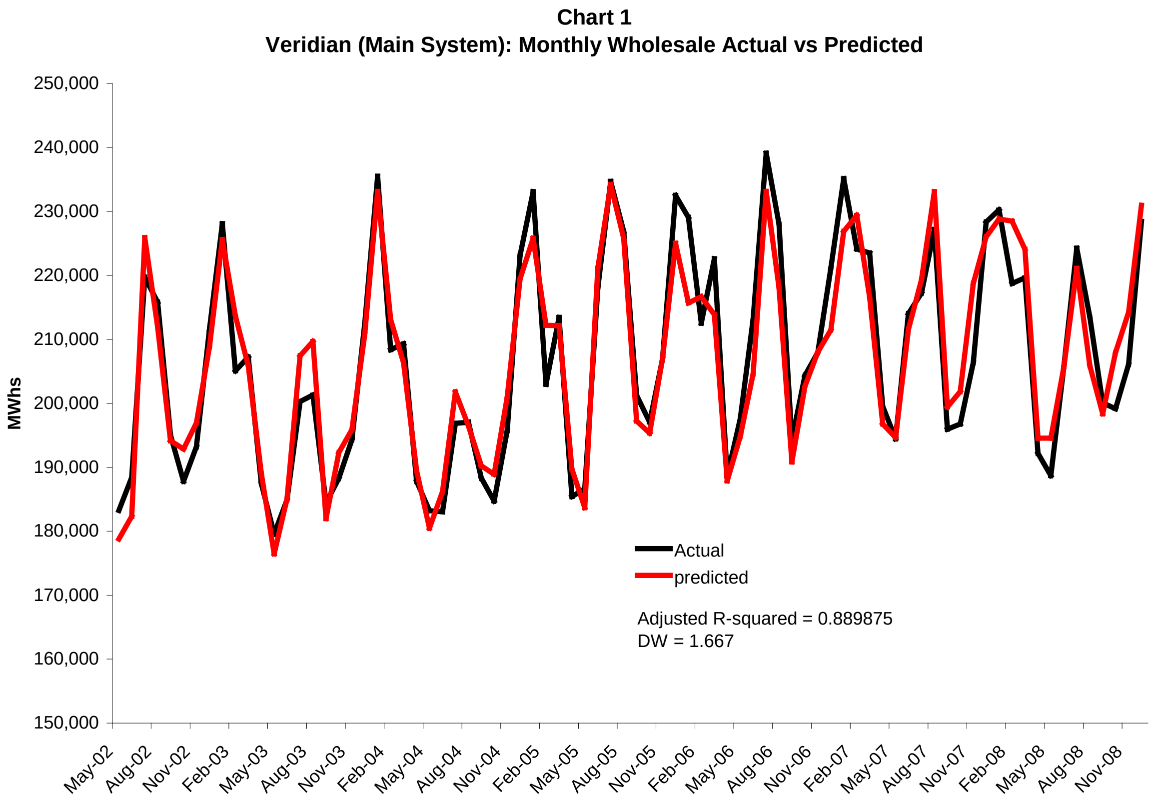
Table 3

OLS estimates using the 80 observations 2002:05-2008:12
Dependent variable: WholesalekWh

Unadjusted R^2 = 0.895451
Adjusted R^2 = 0.889875
F-statistic (4, 75) = 160.5914 (p-value = 5.80e-36)
Durbin-Watson statistic = 1.667623

Variable	*Coefficient*	*t-statistic*	*p-value*
const	-74,198,156.787	-3.345	0.0013
HDD	81,222.550	23.87	<0.00001
CDD	313,634.374	19.27	<0.00001
Peak Days	1,819,826.921	2.992	0.0037
FTE Ontario	39,636.311	11.68	<0.00001

Fitted vs. actual observations are plotted in the chart (Chart 1) below:



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.0% with the largest absolute error on an annual estimate at 2.4%.

Table 4 – Actual Deliveries vs. Estimates, VCI Main

Year	*Actual wholesale kWh*	*Predicted kWh*	*Absolute % Error*
2003	2,373,316,465	2,393,726,810	0.9%
2004	2,393,015,080	2,406,455,051	0.6%
2005	2,538,717,128	2,529,122,474	0.4%
2006	2,558,350,419	2,497,620,465	2.4%
2007	2,562,505,950	2,574,195,124	0.5%
2008	2,526,783,479	2,554,694,080	1.1%
		Mean Absolute Percentage Error	***1.0%***

2.2 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes “weather normal” over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called “de Bever” method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681). On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. We have adopted the 10 year average from 1999 to 2008 as the definition of weather normal for VCI Main’s weather correction analysis. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the “average” weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing.

Presented below is a table outlining the 10-year monthly HDD and CDD for Pearson International Airport, the weather station selected for VCI Main.

Table 5 –10-yr average (1999-2008) HDD and CDD, Pearson Int'l Airport

Heating Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	749.8	548.1	550.6	296.7	97.1	25.0	0.0	8.4	49.3	267.6	367.5	579.3	3539.4
2000	738.9	612.7	418.6	339.2	139.6	34.5	6.6	11.5	99.5	212.7	432.0	780.3	3,826.1
2001	684.9	587.6	566.6	293.8	111.5	29.8	9.3	0.0	73.6	232.5	325.8	505.0	3,420.4
2002	572.2	540.2	545.6	329.5	227.5	36.2	0.0	0.2	21.8	292.2	445.0	619.4	3,629.8
2003	814.5	699.0	581.1	372.5	177.9	43.4	0.2	2.0	54.9	276.0	398.5	561.5	3,981.5
2004	849.1	631.7	487.3	331.5	158.9	44.2	3.6	12.8	30.0	226.3	379.1	643.4	3,797.9
2005	770.0	616.4	608.6	306.8	189.4	8.9	0.0	0.2	22.6	220.2	388.4	665.3	3,796.8
2006	551.8	604.3	516.6	293.3	136.9	19.5	0.0	4.2	80.9	288.3	382.2	500.5	3,378.5
2007	647.1	740.1	546.7	356.4	136.4	16.5	3.2	5.2	36.9	137.7	462.5	630.7	3,719.4
2008	623.5	674.7	610.2	253.9	193.5	22.7	1.0	12.7	59.0	278.6	451.6	654.6	3,836.0
10-yr avg	***700.2***	***625.5***	***543.2***	***317.4***	***156.9***	***28.1***	***2.4***	***5.7***	***52.9***	***243.2***	***403.3***	***614.0***	***3692.6***

Cooling Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	0.0	0.0	0.0	0.0	19.4	96.0	196.5	79.1	48.9	0.0	0.0	0.0	439.9
2000	0.0	0.0	0.0	0.0	23.7	41.1	71.8	92.5	35.2	1.2	0.0	0.0	265.5
2001	0.0	0.0	0.0	1.4	12.2	79.7	100.9	160.0	35.7	2.0	0.0	0.0	391.9
2002	0.0	0.0	0.0	8.3	7.8	70.0	192.4	142.7	87.6	10.0	0.0	0.0	518.8
2003	0.0	0.0	0.0	2.4	0.0	52.9	118.3	128.0	24.0	0.0	0.0	0.0	325.6
2004	0.0	0.0	0.0	0.0	8.6	31.6	86.4	59.6	41.2	1.5	0.0	0.0	228.9
2005	0.0	0.0	0.0	0.0	0.8	146.3	188.7	140.7	52.1	7.6	0.0	0.0	536.2
2006	0.0	0.0	0.0	0.0	26.0	73.6	167.3	101.6	12.9	1.1	0.0	0.0	382.5
2007	0.0	0.0	0.0	0.0	22.4	99.2	106.1	141.0	47.5	19.8	0.0	0.0	436
2008	0.0	0.0	0.0	0.0	2.5	71.5	111.0	64.0	26.7	0.0	0.0	0.0	275.7
10-yr avg	***0.0***	***0.0***	***0.0***	***1.2***	***12.3***	***76.2***	***133.9***	***110.9***	***41.2***	***4.3***	***0.0***	***0.0***	***380.1***

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 6 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(March 20,2009)*	RBC *(Mar 2009)*	Scotia *(Mar. 17, 2009)*	TD *(Mar 17,2009)*	Avg
2009	-3.1	-1.9	-2.6	-2.6	-2.6
2010	0.6	1.3	0.2	-0.6	0.4

Incorporating the forecast economic variables, peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

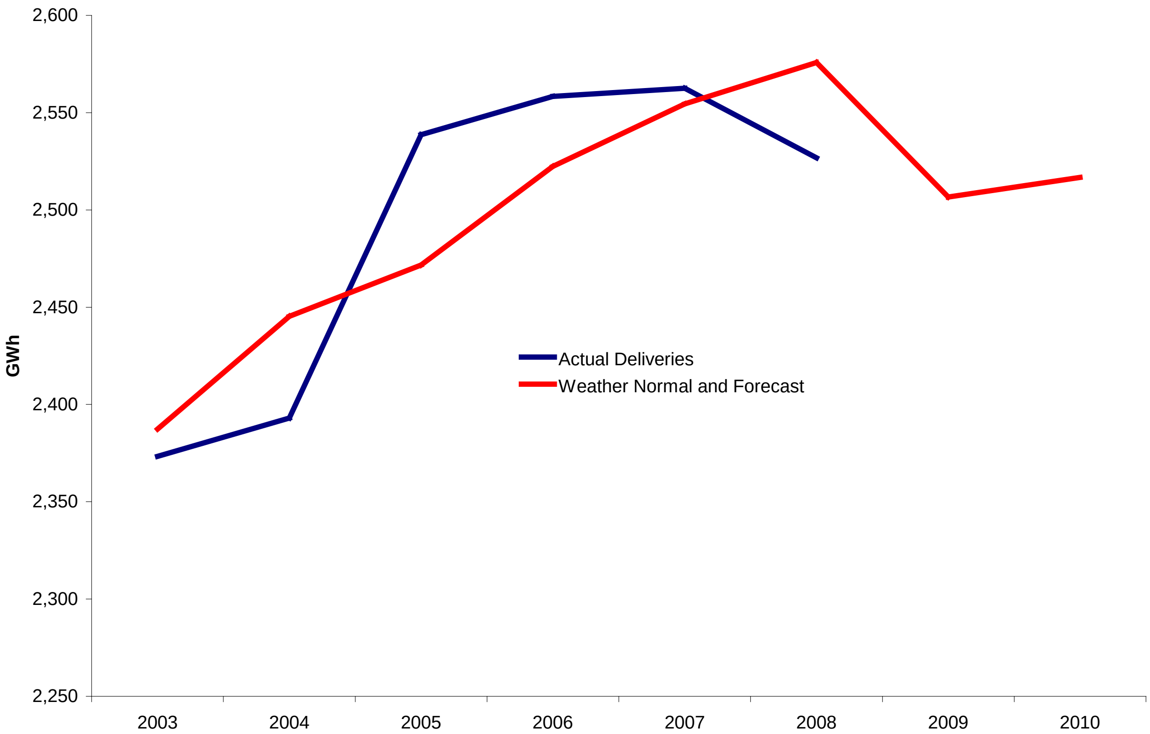
Table 7 - Weather Corrected Wholesale kWh, VCI Main

Year	Actual wholesale kWh	%chg	10-yr (1999-2008) Weather Normal	%chg
2003	2,373,316,465		2,387,353,064	
2004	2,393,015,080	*0.8%*	2,445,322,210	*2.4%*
2005	2,538,717,128	*6.1%*	2,471,699,134	*1.1%*
2006	2,558,350,419	*0.8%*	2,522,378,121	*2.1%*
2007	2,562,505,950	*0.2%*	2,554,484,574	*1.3%*
2008	2,526,783,479	*-1.4%*	2,575,788,571	*0.8%*

2009F			2,506,626,643	-2.7%
2010F			2,516,710,137	0.4%

Chart 2 below displays actual wholesale deliveries (GWh) and weather normalized historic and forecast.

Chart 2
Annual Delivered GWh - Weather Actual vs Weather Normal - VCI Main



2.3 ALLOCATION TO SPECIFIC CLASSES

The following table (Table 8) presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2008.

Table 8
Weather Corrected Class Specific Consumption, VCI Main

			10-yr (1999-2008)
Year	Actual residential kWh	*Share%*[1]	Weather Normal
2003	827,059,131	34.8%	831,950,639
2004	831,017,028	34.7%	849,181,609
2005	906,779,281	35.7%	882,841,786
2006	883,724,953	34.5%	871,299,127
2007	915,566,674	35.7%	912,700,688
2008	931,097,742	36.8%	949,155,692
2009F			923,670,123
2010F			927,385,803
Year	Actual GS<50 kWh	*Share%*	Weather Normal
2003	276,521,722	11.7%	278,157,165
2004	281,226,049	11.8%	287,373,159
2005	283,135,116	11.2%	275,660,811
2006	294,123,554	11.5%	289,987,960
2007	291,605,781	11.4%	290,692,972
2008	296,146,633	11.7%	301,890,178
2009F			293,784,191
2010F			294,966,007
Year	Actual GS>50 kWh	*Share%*	Weather Normal
2003	964,152,305	40.6%	969,854,629
2004	942,013,909	39.4%	962,604,688
2005	1,005,862,450	39.6%	979,309,321
2006	983,029,977	38.4%	969,207,849
2007	966,922,043	37.7%	963,895,300
2008	931,775,076	36.9%	949,846,163
2009F			924,342,054
2010F			928,060,437

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 9 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the average of the class kW to class kWh ratio in 2008.

[1] Share % represents the share of actual metered (non loss adjusted) annual class consumption in actual annual wholesale deliveries measured at the wholesale point of delivery.

Table 9 – GS>50 Class kW (Actual, Normalized, and Forecast), VCI Main

Year	Actual kW	Class kW/kWh ratio	Normalized kW
2003	2,373,086	0.00246	2,387,121
2004	2,316,944	0.00246	2,367,588
2005	2,500,118	0.00249	2,434,119
2006	2,332,139	0.00237	2,299,347
2007	2,331,031	0.00241	2,323,735
2008	2,417,886	0.00259	2,464,779
2009F			2,398,598
2010F			2,408,247

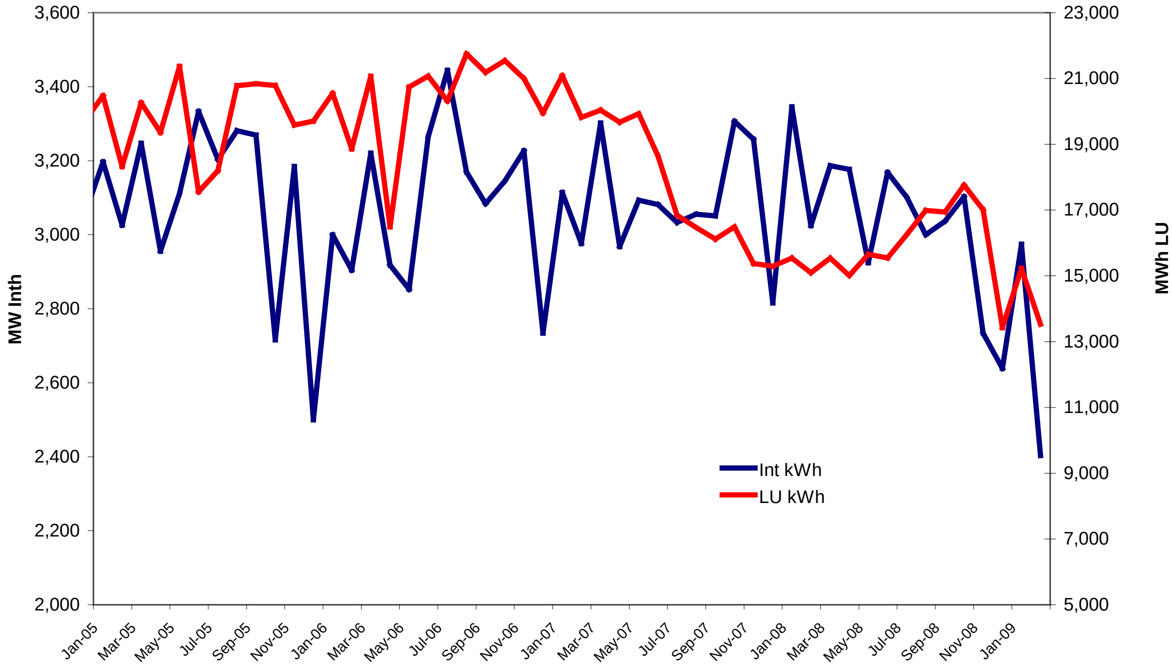
NON-WEATHER SENSITIVE CLASSES AND CUSTOMER CONNECTION FORECAST

Table 11 below presents actual and forecast kWh and kW (where applicable) for the non-weather sensitive classes. These include Intermediate, Large Use, Street Lighting, Sentinel Lighting and Unmetered Scattered Load (USL).

The Intermediate Class consists of two customers and the Large Use Class consists of five customers.[2] Since these customers are interval metered, we have access to monthly consumption levels for these classes. Both these classes have had declining consumption over the past few years. In the case of Large Use, this decline started in 2007 and continued into 2008. In the case of the Intermediate Class, consumption has been flat since 2004 and began to decline in 2008.

[2] In 2006 two (2) customers that were previously classified as GS>50 were reallocated; one (1) to Intermediate and one (1) to Large Use. For the purposes of load forecasting, customer classes have been defined as they exist currently and these customers and their consumption have been allocated to their current rate class for the entire time series.

Chart 3
Monthly Intermediate and Large Use Consumption - VCI Main Jan'07 - Feb'09



Several of these customers are in industrial sectors that are currently facing challenges, so we are forecasting a decline in consumption (based on the most recent 4 months compared to the previous 4 months). In 2010, the forecast for Intermediate and LU kWh and kW is in line with the overall forecast for wholesale purchases (0.4%).

Table 10
Intermediate and Large User kWh and kW

	Int kWh	*% chg*	Int kW	*% chg*	LU kWh	*% chg*	LU kW	*% chg*
Jul'08-Oct'08	12,241,842		30,421		67,943,391		118,175	
Nov'08-Feb'09	10,749,920	-12.2%	28,832	-5.2%	59,188,981	-12.9%	110,172	-6.8%

Forecast throughput for Street Lighting, Sentinel Lighting and USL is based on the most recent actual use per customer (2008) and the forecast change in customers for these classes. We do not anticipate an increase in the rate of growth of street light attachments in 2009 and 2010 as the increase in street lighting is directly tied to growth in new subdivisions. Based on preliminary data from CMHC, new housing development is forecast to decline significantly in 2009 and 2010. Therefore, we are forecasting the number of streetlamp additions to grow at the level seen in 2008 (at 1.9% per year). Initial data for 2009 indicate that housing starts have slowed significantly. First Quarter 2009 Housing Starts for Durham Region (excluding Whitby and Oshawa) are almost 40 per cent lower than the same period last year (194 versus 311).[3] Completions (Durham Region excluding Oshawa and Whitby) are also down by over 8 per cent (439 versus 478), reflecting the downwards trend in starts in 2008. As the reduction in starts in 2009 percolates into the completions, it is expected that residential attachments will slow. In 2008, there were about 1,500 attachments (December 2008 versus 2007) and about 1,600 comparing 2008 average to 2007 average. In 2009, we are anticipating 1,080 residential attachments based on first quarter completions and starts, slowing to about 800 in 2010, or about half the level in 2008.

The number of Sentinel lights has remained constant for several years and we are not anticipating any additional connections. Since 2006, USL use per customer has declined substantially each year. Class USL consumption has also declined each year since 2006. We have forecast USL class consumption to decrease in 2009 and 2010 similar to 2008. No new USL attachments are forecast.

The forecast class kW for Street and Sentinel Lighting is based on the 2008 ratio of annual kW to annual kWh.

Table 11 below summarizes the lighting and USL consumption forecast. Table 12 summarizes the customer connection forecast (average annual).

Table 11

Non-Weather Sensitive Historic and Forecast Consumption – VCI Main

	Intermediate				*Large user*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	34,078,609		94,444		233,123,423		409,790	
2004	37,212,454	*9.2%*	94,712	*0.3%*	220,209,114	*-5.5%*	368,851	*-10.0%*
2005	37,025,068	*-0.5%*	97,817	*3.3%*	237,241,914	*7.7%*	412,936	*12.0%*
2006	36,964,611	*-0.2%*	93,531	*-4.4%*	244,544,213	*3.1%*	422,374	*2.3%*
2007	37,056,537	*0.2%*	93,248	*-0.3%*	215,781,718	*-11.8%*	382,076	*-9.5%*
2008	36,441,211	*-1.7%*	90,282	*-3.2%*	190,773,043	*-11.6%*	333,810	*-12.6%*
2009F	32,068,266	*-12.0%*	85,768	*-5.0%*	165,972,547	*-13.0%*	310,443	*-7.0%*

[3] Housing Now – Greater Toronto Area, April 2009.

2010F	32,196,539	*0.4%*	86,111	*0.4%*	166,636,438	*0.4%*	311,685	*0.4%*

	Street Lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003								
2004								
2005	19,530,434		46,500		972,712		2,702	
2006	18,461,322	*-5.5%*	51,125	*9.9%*	802,732	*-17.5%*	2,230	*-17.5%*
2007	18,376,945	*-0.5%*	51,647	*1.0%*	928,755	*15.7%*	2,530	*13.4%*
2008	18,811,565	*2.4%*	52,584	*1.8%*	846,470	*-8.9%*	2,353	*-7.0%*
2009F	19,168,984	*1.9%*	53,583	*1.9%*	846,470	*0.0%*	2,353	*0.0%*
2010F	19,533,195	*1.9%*	54,601	*1.9%*	846,470	*0.0%*	2,353	*0.0%*

USL (Unmetered Scattered Load)

Year	kWh	%
2003		
2004		
2005	6,814,866	
2006	6,557,788	*-3.8%*
2007	5,907,835	*-9.9%*
2008	5,738,246	*-2.9%*
2009F	5,573,526	*-2.9%*
2010F	5,413,534	*-2.9%*

Table 12 – Average Annual Customer Connections – VCI Main

	2003	2004	2005	2006	2007	2008	2009F	2010F
Residential	82,572	83,188	86,769	90,518	92,815	94,490	95,570	96,370
% chg		*0.7%*	*4.3%*	*4.3%*	*2.5%*	*1.8%*	*1.1%*	*0.8%*
GS<50 kW	7,262	7,160	7,450	7,565	7,604	7,655	7,706	7,758
% chg		*-1.4%*	*4.0%*	*1.5%*	*0.5%*	*0.7%*	*0.7%*	*0.7%*
GS> 50 kW	962	973	996	1,012	1,020	1,038	1,038	1,038
% chg		*1.2%*	*2.4%*	*1.6%*	*0.8%*	*1.8%*	*0.0%*	*0.0%*
Intermediate	2	2	2	2	2	2	2	2
Large Use	5	5	5	5	5	5	5	5
Street Light	22,076	22,599	23,711	24,584	25,568	26,046	26,541	27,045
% chg		*2.4%*	*4.9%*	*3.7%*	*4.0%*	*1.9%*	*1.9%*	*1.9%*
Sentinel Light	800	784	655	655	730	730	730	730
USL	734	747	756	759	868	875	875	875
% chg		*1.8%*	*1.2%*	*0.3%*	*14.4%*	*0.7%*	*0.0%*	*0.0%*

Table 13 below presents the results for class specific historic actual and historic normalized (2008) kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 13 – VCI Main Load Forecast (Historical, Bridge and Test Years).

	2008 Actual	2008 Normalized	2009f Normalized	2010f Normalized
Residential (kWh)	931,097,742	949,155,692	923,670,123	927,385,803
GS<50 (kWh)	296,146,633	301,890,178	293,784,191	294,966,007
GS>50 (kWh)	931,775,076	949,846,163	924,342,054	928,060,437
(kW)	2,417,886	2,464,779	2,398,598	2,408,247
Intermediate (kWh)	36,441,211	36,441,211	32,068,266	32,196,539
(kW)	90,282	90,282	85,768	86,111
Large Use (kWh)	190,773,043	190,773,043	165,972,547	166,636,438
(kW)	333,810	333,810	310,443	311,685
Street Lights (kWh)	18,811,565	18,811,565	19,168,984	19,533,195
(kW)	52,584	52,584	53,583	54,601
Sentinel Lights (kWh)	846,470	846,470	846,470	846,470
(kW)	2,353	2,353	2,353	2,353
USL (kWh)	5,738,246	5,738,246	5,573,526	5,413,534
Total Retail kWh	2,411,629,986	2,453,502,567	2,365,426,162	2,375,038,423

2.4 AVERAGE USE

Displayed below (Table 14) are the observed actual average use per customer, by customer class, as well as historical weather normalized and weather normal forecast average use per customer generated using our load forecast.

Table 14 - Weather Actual Use Per Customer – VCI Main

Year	Residential	GS<50	GS>50	Intermed.	Large Use	Street	Sentinel	USL
2003	10,016	38,080	1,002,672	17,039,304	46,624,685	730	1,158	6,064
2004	9,990	39,275	968,237	18,606,227	44,041,823	603	1,052	6,542
2005	10,451	38,005	1,009,902	18,512,534	47,448,383	824	1,485	9,011
2006	9,763	38,882	971,854	18,482,305	48,908,843	751	1,226	8,642
2007	9,864	38,349	947,885	18,528,268	43,156,344	719	1,272	6,804
2008	9,854	38,687	897,520	18,220,606	38,154,609	722	1,160	6,560

Weather Normal Use Per Customer – VCI Main

Year	Residential	GS<50	GS>50	Intermed.	Large Use	Street	Sentinel	USL
2003	10,075	38,305	1,008,602	17,039,304	46,624,685	730	1,158	6,064
2004	10,208	40,134	989,401	18,606,227	44,041,823	603	1,052	6,542
2005	10,175	37,001	983,242	18,512,534	47,448,383	824	1,485	9,011
2006	9,626	38,335	958,189	18,482,305	48,908,843	751	1,226	8,642
2007	9,834	38,229	944,918	18,528,268	43,156,344	719	1,272	6,804
2008	10,045	39,437	914,926	18,220,606	38,154,609	722	1,160	6,560
2009	9,665	38,124	890,360	16,034,133	33,194,509	722	1,160	6,370
2010	9,623	38,023	893,942	16,098,269	33,327,288	722	1,160	6,187

3 GRAVENHURST

This section outlines the load forecast for the Gravenhurst system.

As outlined in the Introduction, most customers are billed on a bi-monthly basis and monthly class-specific consumption is not readily available. Therefore, a similar approach to VCI Main (i.e., using monthly wholesale deliveries) is adopted. However, due to the existence of a seasonal rate class, a normalized average use per customer (NAC) approach using previous work on weather normalized throughput for the Cost Allocation Informational Filing (CAIF) will also be utilized.

3.1 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

The following table outlines monthly wholesale deliveries from May 2002 to December 2008.

Table 15: Monthly Actual Energy (kWh), Gravenhurst

	2002	2003	2004	2005	2006	2007	2008
January		11,257,844	12,348,584	11,358,285	9,584,722	10,152,392	10,132,680
February		10,148,070	9,948,240	9,218,958	9,052,892	10,027,994	9,954,857
March		9,527,745	9,072,155	9,421,380	9,095,693	9,266,494	9,754,864
April		7,685,674	7,329,988	7,080,256	6,984,473	7,534,660	7,339,615
May	7,358,898	6,744,262	6,872,231	7,187,520	6,945,761	6,894,173	7,245,582
June	6,826,855	6,699,584	6,477,351	7,298,328	7,054,581	7,206,369	7,100,596
July	8,137,971	7,614,529	7,597,375	8,258,785	8,432,462	7,928,780	8,054,716
August	7,809,094	7,286,578	7,507,039	7,920,991	7,527,204	8,119,385	7,949,031
September	6,696,496	6,464,375	6,706,564	6,706,528	6,773,819	6,793,394	6,875,941
October	7,752,413	7,793,177	7,265,439	7,232,967	7,729,186	7,124,909	7,796,074
November	8,234,050	8,177,397	7,746,269	7,948,692	7,792,725	8,212,919	8,376,163
December	9,823,993	9,897,753	10,212,758	10,109,868	9,154,135	10,196,499	10,406,058
Annual		**99,296,988**	**99,083,993**	**99,742,558**	**96,127,653**	**99,457,968**	**100,986,177**
% change			***-0.2%***	***0.7%***	***-3.6%***	***3.5%***	***1.5%***

For the Gravenhurst system, we have used monthly HDD and CDD as reported at Muskoka Airport, on Hwy 11 between Gravenhurst and Bracebridge. We have used the monthly full-time employment levels for Ontario (CANSIM series v2054816) as the economic indicator, identical to the series used for VCI Main. Peak days did not appear to be statistically significant, however, the number of days in the month did so this was adopted as the calendar variable for Gravenhurst.

Using these data, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual energy deliveries and the explanatory variables.

The resulting equation, estimated using the 80 observations from 2002:05-2008:12 is displayed below:

Table 16

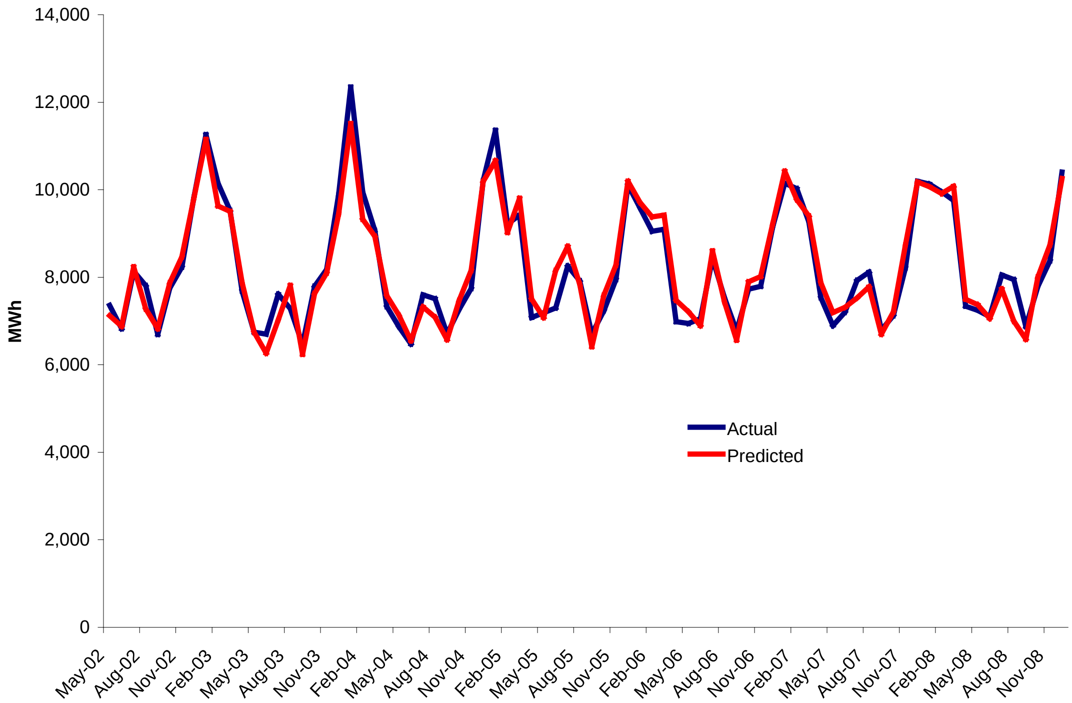
OLS estimates using the 80 observations 2002:05-2008:12
Dependent variable: WholesalekWh

Unadjusted R^2 = 0.937665
Adjusted R^2 = 0.934341
F-statistic (4, 75) = 282.0455 (p-value = 2.29e-44)
Durbin-Watson statistic = 1.333066

Variable	*Coefficient*	*t-statistic*	*p-value*
const	-5,439,665.71	-2.9178	0.00465
HDD	5,717.54	31.3423	<0.00001
CDD	32,484.82	14.1752	<0.00001
Month Days	248,921.60	4.9163	<0.00001
FTE Ontario	650.83	3.0129	0.00353

Fitted vs. actual observations are plotted in the chart (Chart 4) below:

Chart 4
Veridian (Gravenhurst): Monthly Wholesale Actual vs. Predicted



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.3% with the largest absolute error on an annual estimate at 1.9%.

Table 17 – Actual Deliveries vs. Estimates, Gravenhurst

Year	*Actual wholesale kWh*	*Predicted kWh*	*Absolute % Error*
2003	99,296,988	97,427,986	1.9%
2004	99,083,993	97,848,580	1.2%
2005	99,742,558	101,263,506	1.5%
2006	96,127,653	97,841,903	1.8%
2007	99,457,968	100,123,046	0.7%
2008	100,986,177	100,330,670	0.6%
		Mean Absolute Percentage Error	***1.3%***

3.2 WEATHER NORMALIZATION AND FORECASTED KWH

Presented below is a table outlining the 10-year monthly HDD and CDD for Muskoka Airport, the weather station selected for Gravenhurst.

Table 18 –10-yr average (1999-2008) HDD and CDD, Gravenhurst Airport

Heating Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	892.2	668.8	646	350.3	142.9	48.9	14.1	44.4	110.9	355.3	448.9	721	4,443.7
2000	879.5	731.4	510	408.7	199.7	94	44.8	51.2	178	320.7	522.5	919.1	4,859.6
2001	824.3	740.7	666.8	364.7	160.6	68.1	46.1	14.3	151.2	312.2	410.8	605.8	4,365.6
2002	695.8	664.9	674.7	399.4	285.9	65	19.1	25.4	78	391.4	561.6	753.7	4,614.9
2003	990.4	857.5	705	460.9	212.7	74.8	21.9	27.4	113.7	349.8	483.2	676.7	4,974.0
2004	1041.1	746.8	592.8	395.9	236	110.4	21.5	69.8	88.4	310.8	485.2	801	4,899.7
2005	889.9	737.4	746.4	381.2	252.2	35.4	14.8	13.2	78	279.7	491.1	785.6	4,704.9
2006	706.5	783.8	663.4	362.7	181.7	58.5	4.9	43.7	163.5	366.1	441.1	610	4,385.9
2007	826.1	847.5	653.1	426.6	203.5	62.6	39.5	26.7	100.1	226.7	555.2	766.2	4,733.8
2008	753.1	815.6	760.5	348.6	277.3	48.4	13.9	39.4	132.7	372.5	555.9	782.6	4,900.5
10 -yr avg	**849.9**	**759.4**	**661.9**	**389.9**	**215.3**	**66.6**	**24.1**	**35.6**	**119.5**	**328.5**	**495.6**	**742.2**	**4,688.3**

Cooling Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	0	0	0	0	8.8	58.2	86	20.1	23.7	0	0	0	196.8
2000	0	0	0	0	4.9	11.4	28.2	29.3	12.1	0	0	0	85.9
2001	0	0	0	0.1	2.2	36.7	51.7	60.7	15.4	0	0	0	166.8
2002	0	0	0	4.5	1.8	39.3	79.2	46.8	31.5	2.2	0	0	205.3
2003	0	0	0	0	0	15.8	39	60.9	5.6	0	0	0	121.3
2004	0	0	0	0	5.5	15.2	45.2	28.4	17.9	0	0	0	112.2
2005	0	0	0	0	0.4	76.8	87.8	59.8	12.6	6.7	0	0	244.1
2006	0	0	0	0	14	31.3	83.4	39.9	0.7	0	0	0	169.3
2007	0	0	0	0	9.1	43	43.6	52.3	14.4	1.5	0	0	163.9
2008	0	0	0	0	0	36.4	54.1	26	5.1	0	0	0	121.6
10-yr avg	**0.0**	**0.0**	**0.0**	**0.5**	**4.7**	**36.4**	**59.8**	**42.4**	**13.9**	**1.0**	**0.0**	**0.0**	**158.72**

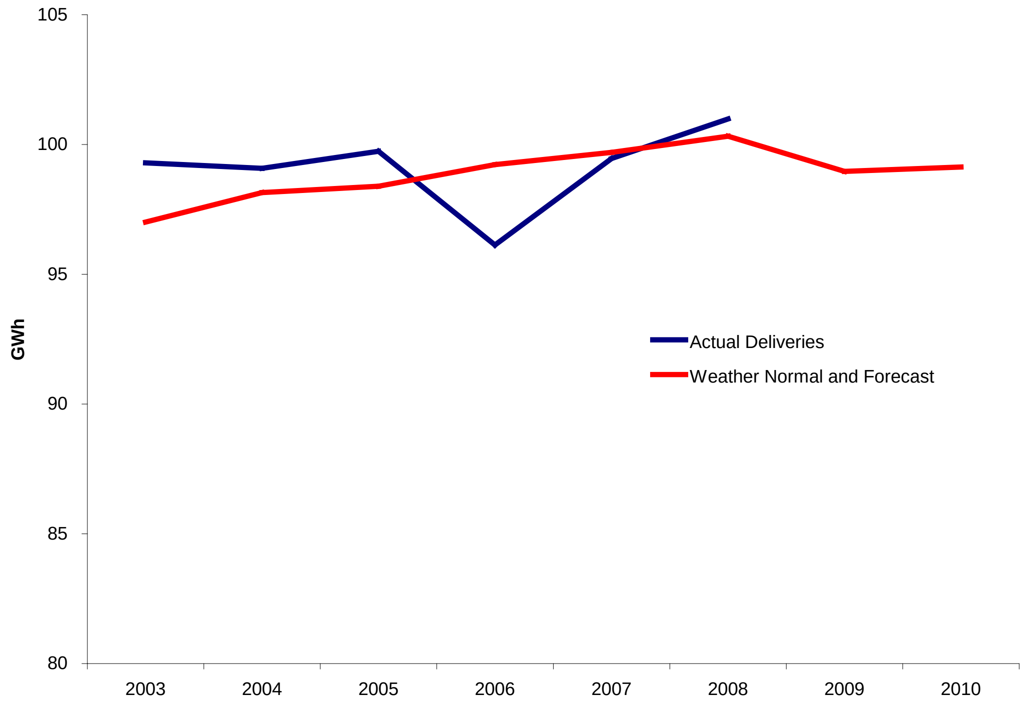
Incorporating the forecast economic variables, peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 19 - Weather Corrected Wholesale kWh, Gravenhurst

			10-yr (1999-2008)	
Year	Actual wholesale kWh	%chg	Weather Normal	%chg
2003	99,296,988		97,009,838	
2004	99,083,993	*-0.2%*	98,150,857	*1.2%*
2005	99,742,558	*0.7%*	98,394,812	*0.2%*
2006	96,127,653	*-3.6%*	99,226,969	*0.8%*
2007	99,457,968	*3.5%*	99,694,398	*0.5%*
2008	100,986,177	*1.5%*	100,323,016	*0.6%*
2009F			98,968,327	*-1.4%*
2010F			99,133,900	*0.2%*

Chart 5 below displays actual wholesale deliveries (GWh) and weather normalized historic and forecast.

Chart 5
Annual Delivered GWh - Weather Actual vs Weather Normal - Gravenhurst



3.3 ALLOCATION TO SPECIFIC CLASSES

Table 21 presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Other than Residential – Seasonal, historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2008. For residential seasonal, we have used the normalized average use per customer (NAC) as determined from weather normalized throughput calculated for Gravenhurst by Hydro One Networks Inc (HON) for the OEB's CAIF. Our understanding is that the class throughput calculated for this process is on a "purchased" or wholesale basis, rather than a retail or metered basis. Therefore, we have calculated the "retail" NAC by first determining an implied loss rate. This is determined by dividing the HON determined weather actual class throughput by our retail metered kWh class throughput for 2004. We then calculated the weather normal retail class throughput by dividing the HON determined value by the implied loss factor. The NAC was then determined by dividing the weather normal retail class throughput by the number of customers[4] in 2004. A summary of these calculations is presented in Table 20. Only the NAC for Residential – Seasonal is used for our forecasting process.

Table 20 – Retail NAC, Gravenhurst (2004)

Monthly kWh by class (with actual weather)	TOTAL	2004 Retail	Implied Loss
1 Residential class - Urban	31,571,142	28,756,656	1.10
2 Residential class - Sub Urban	10,343,143	9,429,687	1.10
3 Residential class - Seasonal	10,467,601	9,746,152	1.07
4 Streetlights	601,985	562,253	1.07
5 Sentinellights	58,922	50,909	1.16
6 General service <50kW	15,067,578	14,005,270	1.08
7 General service >50kW	32,449,823	29,303,869	1.11

Monthly kWh by class (with normalized weather)	TOTAL	Retail	2004 Cust (YE)	Retail NAC
1 Residential class - Urban	31,888,690	29,045,895	2,896	10,030
2 Residential class - Sub Urban	10,452,464	9,529,353	677	14,076
3 Residential class - Seasonal	10,608,581	9,877,415	1,616	6,112
4 Streetlights	601,985		911	
5 Sentinellights	58,922		78	
6 General service <50kW	15,230,959	14,157,132	646	21,915
7 General service >50kW	32,784,906	29,606,466	56	528,687

Table 21
Weather Corrected Class Specific Consumption, Gravenhurst

			10-yr (1999-2008)
Year	Actual Res-Urban kWh	*Share%*	Weather Normal
2003	29,006,946	*29.2%*	28,338,817
2004	28,756,656	*29.0%*	28,485,837
2005	27,802,515	*27.9%*	27,426,840
2006	27,755,227	*28.9%*	28,650,101
2007	27,805,722	*28.0%*	27,871,821
2008	27,908,978	*27.6%*	27,725,704
2009F			27,351,317
2010F			27,397,075
Year	Actual Res-SubUrban kWh	*Share%*	Weather Normal
2003	9,528,483	*9.6%*	9,309,009
2004	9,429,687	*9.5%*	9,340,882
2005	9,347,873	*9.4%*	9,221,562
2006	9,209,258	*9.6%*	9,506,180
2007	8,691,488	*8.7%*	8,712,150
2008	9,634,733	*9.5%*	9,571,463
2009F			9,442,217
2010F			9,458,013

[4] Gravenhurst only has year-end customer counts from 2002 to 2005. Starting in 2006, monthly customer counts are available.

Year	Actual Res-Seasonal kWh	*Share%*	Weather Normal
2003	10,256,598		9,822,405
2004	9,746,152		9,877,415
2005	9,388,779		9,852,966
2006	8,778,367		9,860,606
2007	9,147,921		9,822,914
2008	9,610,542		9,794,390
2009F			9,773,507
2010F			9,755,170
Year	Actual GS<50 kWh	*Share%*	Weather Normal
2003	14,513,844	*14.6%*	14,179,540
2004	14,005,270	*14.1%*	13,873,373
2005	15,040,125	*15.1%*	14,836,899
2006	14,147,239	*14.7%*	14,603,370
2007	15,156,079	*15.2%*	15,192,108
2008	15,044,960	*14.9%*	14,946,162
2009F			14,744,340
2010F			14,769,007
Year	Actual GS>50 kWh	*Share%*	Weather Normal
2003	29,139,113	*29.3%*	28,467,939
2004	29,303,869	*29.6%*	29,027,896
2005	31,290,254	*31.4%*	30,867,452
2006	27,537,777	*28.6%*	28,425,641
2007	28,197,792	*28.4%*	28,264,823
2008	29,204,094	*28.9%*	29,012,315
2009F			28,620,554
2010F			28,668,436

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 22 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the average of the class kW to class kWh ratio in 2008.

Table 22 – GS>50 Class kW (Actual, Normalized, and Forecast), Gravenhurst

Year	**Actual kW**	**Class kW/kWh ratio**	**Normalized kW**
2003	83,097	0.002852	81,183
2004	82,326	0.002809	81,551
2005	73,065	0.002335	72,078
2006	74,129	0.002692	76,519
2007	67,173	0.002382	67,333
2008	69,971	0.002396	69,511
2009F			68,573

2010F	68,687

NON-WEATHER SENSITIVE STREET AND SENTINEL LIGHTS

Table 23 below presents actual and forecast kWh and kW Street Lighting and Sentinel Lighting. No new lighting attachments are expected in the current climate and use is expected to remain at 2008 levels.

Table 23: Gravenhurst Street Lights and Sentinel Lights Consumption

	Street Lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	621,393		1,716		51,040			
2004	562,253	*-9.5%*	1,572	*-8.4%*	50,909	*-0.3%*	141	
2005	558,781	*-0.6%*	1,493	*-5.0%*	46,937	*-7.8%*	120	*-15.4%*
2006	562,239	*0.6%*	1,567	*5.0%*	51,463	*9.6%*	152	*26.9%*
2007	573,742	*2.0%*	1,612	*2.8%*	46,220	*-10.2%*	122	*-19.6%*
2008	598,709	*4.4%*	1,664	*3.2%*	43,727	*-5.4%*	127	*3.6%*
2009F	598,709	*0.0%*	1,664	*0.0%*	43,727	*0.0%*	127	
2010F	598,709	*0.0%*	1,664	*0.0%*	43,727	*0.0%*	127	

Table 24 below presents the results for class specific historic actual and historic normalized (2008) kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 24 – Gravenhurst Load Forecast (Historical, Bridge and Test Years).

	2008 Actual	2008 Normalized	2009f Normalized	2010f Normalized
Residential - Urban (kWh)	27,908,978	27,725,704	27,351,317	27,397,075
Residential - SubUrban (kWh)	9,634,733	9,571,463	9,442,217	9,458,013
Residential - Seasonal (kWh)	9,610,542	9,794,390	9,761,282	9,730,721
GS<50 (kWh)	15,044,960	14,946,162	14,744,340	14,769,007
GS>50 (kWh)	29,204,094	29,012,315	28,620,554	28,668,436
(kW)	69,971	69,511	68,573	68,687
Street Lights (kWh)	598,709	598,709	598,709	598,709
(kW)	1,664	1,664	1,664	1,664
Sentinel Lights (kWh)	43,727	43,727	43,727	43,727
(kW)	127	127	127	127
Total Retail kWh	92,045,742	91,692,470	90,562,145	90,665,687

3.4 CUSTOMER CONNECTIONS

Until 2006, Gravenhurst only has year-end customer counts. From 2006 onwards, monthly customer counts are available and the customer counts from 2006 onwards in the table below (Table 25) reflect annual average number of customer connections. No new customer connections are anticipated for GS>50, Street lights or Sentinel lights over the forecast period. For the remaining customer classes, the annual average growth in connections over the 2006 – 2008 period is used to project customer connections.

Table 25 – Annual Customer Connections – Gravenhurst

	2003	2004	2005	2006	2007	2008	2009F	2010F
Res - Urban	2,868	2,896	2,900	2,906	2,930	2,945	2,965	2,985
% chg	*1.2%*	*1.0%*	*0.1%*	*0.2%*	*0.8%*	*0.5%*	*0.7%*	*0.7%*
Res - SubUrban	664	677	689	700	719	728	742	757
% chg	*1.4%*	*2.0%*	*1.8%*	*1.6%*	*2.7%*	*1.2%*	*2.0%*	*2.0%*
Res - Seasonal	1,607	1,616	1,612	1,613	1,607	1,602	1,597	1,592
% chg	*-0.1%*	*0.6%*	*-0.2%*	*0.1%*	*-0.4%*	*-0.3%*	*-0.3%*	*-0.3%*
GS < 50 kW	641	646	657	677	694	702	714	727
% chg	*1.1%*	*0.8%*	*1.7%*	*3.0%*	*2.5%*	*1.1%*	*1.8%*	*1.8%*
GS > 50 kW	57	56	58	54	50	50	50	50
% chg	*1.8%*	*-1.8%*	*3.6%*	*-6.8%*	*-7.2%*	*0.0%*	*0.0%*	*0.0%*
Street Light	911	911	906	906	921	947	947	947
% chg	*0.0%*	*0.0%*	*-0.5%*	*0.0%*	*1.7%*	*2.8%*	*0.0%*	*0.0%*
Sentinel Light	78	78	53	53	53	53	53	53

3.5 AVERAGE USE

Table 26 – Average Use – Gravenhurst

Actual Use Per Customer	2003	2004	2005	2006	2007	2008
Res - Urban	10,114	9,930	9,587	9,550	9,491	9,475
Res - Suburban	14,350	13,929	13,567	13,158	12,087	13,241
Res - Seasonal	6,382	6,031	5,824	5,441	5,692	5,998
GS < 50	22,643	21,680	22,892	20,907	21,841	21,444
GS > 50	511,213	523,283	539,487	509,173	562,082	582,141
Sentinel Lighting	654	653	886	971	872	825
Street Lighting	682	617	617	621	623	632

Normalized Use Per Customer	2003	2004	2005	2006	2007	2008	2009	2010
Res - Urban	9,881	9,836	9,458	9,858	9,514	9,413	9,225	9,178
Res - Suburban	14,020	13,797	13,384	13,582	12,116	13,154	12,725	12,494
Res - Seasonal	6,112	6,112	6,112	6,112	6,112	6,112	6,112	6,112
GS < 50	22,121	21,476	22,583	21,581	21,893	21,303	20,650	20,315
GS > 50	499,438	518,355	532,197	525,590	563,418	578,319	572,411	573,369
Sentinel Lighting	654	653	886	971	872	825	825	825
Street Lighting	682	617	617	621	623	632	632	632

Appendix E

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

Ontario

EB-2011-0100

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Enersource Hydro Mississauga Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

BEFORE: Karen Taylor
Presiding Member

Paula Conboy
Member

DECISION AND ORDER

Introduction

Enersource Hydro Mississauga Inc. ("Enersource"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on November 10, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Enersource charges for electricity distribution, to be effective May 1, 2012.

Enersource is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, establishes a three year plan term for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the 3rd generation IRM plan until such time as the RRFE policy initiatives have been substantially completed. As part of the plan, Enersource is one of the electricity distributors that will have its rates adjusted for 2012 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "*Supplemental Report*"), and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports contain the relevant guidelines for 2012 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 22, 2011 the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the Filing Requirements for IRM applications based on the policies in the Reports.

Notice of Enersource's rate application was given through newspaper publication in Enersource's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. One letter of comment was received. The Notice of Application indicated that intervenors would be eligible for cost awards with respect to Enersource's request for lost revenue adjustment mechanism ("LRAM") recoveries. The Vulnerable Energy Consumers Coalition ("VECC") and Ms. L. Volnyansky applied for and were granted intervenor status in this proceeding. The Board granted VECC eligibility for cost awards in regards to Enersource's request for LRAM recoveries. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Account 1521: Special Purpose Charge;
- Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes;

- Review and Disposition of Lost Revenue Adjustment Mechanism; and
- Smart Meter Funding Adder (“SMFA”).

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator, less a productivity factor (X-factor) of 0.72% and a stretch factor.

On March 13, 2012, the Board announced a price escalator of 2.0% for those distributors under IRM that have a rate year commencing May 1, 2012.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated December 1, 2011 the Board assigned to Enersource efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes that are not eligible for Rural or Remote Electricity Rate Protection. The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The final Tariff of Rates and Charges attached to this Decision and Order reflects the new RRRP charge.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction over the IRM plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

Enersource's application identified a total tax savings of $3,109,782 resulting in a shared amount of $1,554,891 to be refunded to rate payers.

In its submission, Board staff noted that Enersource completed the Tax-Savings Workform with the correct rates which reflect the Revenue Requirement Work Form from the Board's cost of service decision in EB-2007-0706. Board staff had no concerns with the workform as filed.

The Board approves shared tax savings of $1,554,891 to be disposed over a one year period, May 1, 2012 to April 30, 2013.

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2011 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2012. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table:

2012 Uniform Transmission Rates

Network Service Rate	$3.57 per kW
<u>Connection Service Rates</u> Line Connection Service Rate Transformation Connection Service Rate	 $0.80 per kW $1.86 per kW

In its submission, Board staff noted that it had no concerns with the RTSR Workform as filed.

The Board finds that the 2012 UTRs are to be incorporated into the filing module.

Review and Disposition of Account 1521: Special Purpose Charge

The Board authorized Account 1521, Special Purpose Charge Assessment ("SPC") Variance Account in accordance with Section 8 of Ontario Regulation 66/10 (Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs) (the "SPC Regulation"). Accordingly, any difference between (a) the amount remitted to the Minister of Finance for the distributor's SPC assessment and (b) the amounts recovered from customers on account of the assessment were to be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance. The Filing Requirements state the Board's expectation that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

Enersource provided a reconciliation of Account 1521 as requested by Board staff during the interrogatory phase. Based on Enersource's reconciliation, Board staff supported Enersource's request to dispose of the balance in this account of a credit of $139,554.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, plus the amounts recovered from customers in 2011, including interest, because the account balance does not require a prudence review and electricity distributors are required by regulation to apply for disposition of this account. Board staff submitted that the $139,554 credit balance in Account 1521 should be approved for disposition over a one year period, as requested by Enersource.

The Board approves, on a final basis, the disposition of a credit balance of $139,554 in Account 1521, representing principal and interest to April 30, 2012, over a one year period, May 1, 2012 to April 30, 2013. The Board directs Enersource to close Account 1521 effective May 1, 2012.

For accounting and reporting purposes, the balance of Account 1521 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes

In 2001, the Board approved a regulatory payments in lieu of taxes proxy approach for rate applications coupled with a true-up mechanism filed under the RRR to account for changes in tax legislation and rules and to true-up between certain proxy amounts used to set rates and the actual amount of taxes paid. The variances resulting from the true-up were tracked in Account 1562 for the period 2001 through April 30, 2006.

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Board commenced a Combined Proceeding (EB-2008-0381) on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications.

The Notice in the Combined Proceeding included a statement of the Board's expectation that the decision resulting from the Combined Proceeding would be used to determine the final account balances with respect to Account 1562 Deferred PILs for the remaining distributors. In its decision and order, the Board stated that: "Each remaining distributor will be expected to apply for final disposition of account 1562 with its next general rates application (either IRM or cost of service)."[1]

In pre-filed evidence, Enersource applied to refund to customers a credit balance of $1,184,236 consisting of a principal credit amount of $1,515,868 and related debit carrying charges of $331,632. In response to interrogatories, Enersource updated its evidence and requested to dispose of a total credit amount of $1,093,604.[2]

Two PILs issues remain to be resolved in this case. One relates to the definition of interest expense for calculating the excess interest true-up calculations in the SIMPIL[3] models. The second issue pertains to accounts receivable written off as bad debts in the fourth quarter 2001.

<u>Excess Interest True-up Calculations</u>

In response to Board staff interrogatories, in its final submission and in SIMPIL models, Enersource disclosed the components of its interest expense for the period 2001 to 2005.[4]

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[1] EB-2008-0381 Account 1562 Deferred PILs Combined Proceeding, Decision and Order, p. 28
[2] Responses to Board Staff, January 27, 2012, Interrogatory #9, page 1.
[3] Spreadsheet implementation model for payments in lieu of taxes
[4] Reponses to Board Staff Interrogatory #10; Final Submission, paragraph #52; 2001 SIMPIL model.

Interest Expense Components	**2001**	**2002**	**2003**	**2004**	**2005**
Interest on Debt	4,454,000	18,241,000	18,241,000	18,241,000	18,241,000
Other Interest - Reply					
Interest on customer deposits		477,390	644,770	493,434	461,709
Amortization of debt issue costs	111,694	433,584	433,584	433,584	433,584
Bank overdraft interest		78,989	484		
Rounding		37	162	-18	-293
Other interest expense	111,694	990,000	1,079,000	927,000	895,000
Total interest expense	4,565,694	19,231,000	19,320,000	19,168,000	19,136,000
AFUDC and carrying charges		-772,000	-915,000	-4,113,000	-1,459,000
Interest expense per AFS	4,565,694	18,459,000	18,405,000	15,055,000	17,677,000
Interest income	-511,000	-724,000	-1,938,000	-1,782,000	-1,718,000
Net interest expense	4,054,694	17,735,000	16,467,000	13,273,000	15,959,000

Board staff noted that in its 2012 IRM proceeding (EB-2011-0174), Hydro One Brampton ("HOBNI") defined interest expense for the purpose of the interest claw-back penalty as the net interest expense reported in its financial statements.[5] HOBNI grouped several types of interest income, expense and amortization of deferred debt costs in determining its financial statement disclosure.

The Board in its decision made the following findings in that application:

> The Board finds that the components which will comprise interest expense for purposes of the true-up calculations based on HOBNI's evidence in this case are interest on long-term debt, accounting amortization of deferred debt costs, foreign exchange and interest expense (*other*). After making the changes in HOBNI's SIMPIL models and the continuity schedule to reflect these findings, the Board has determined that the amended credit balance in Account 1562 Deferred PILs is $3,675,429 to be refunded to customers over one year.
>
> While audited financial statement disclosures may vary among the distributors, the Board is not persuaded that interest income should be netted against interest expense in the SIMPIL true-up calculations since this treatment is not consistent with cost of service filing instructions. In the decision in the Combined

[5] EB-2011-0174/Response to Staff IRs/Tab11/Sch2/IR#11/pg20 ln13-25/pg21ln 1-4.

> Proceeding, the Board accepted the settlement that the impacts of regulatory assets and liabilities should be excluded from the determination of the balance in account 1562 deferred PILs, and the Board agrees with that determination in this case. Interest expense related to customer deposits is not recovered in cost of service applications and therefore should be excluded in the SIMPIL calculations. Capitalized interest and its reversal in the tax calculations nets to zero, and this treatment is consistent with prior guidance issued by the Board.[6]

With respect to the current application, Board staff submitted that the components of interest expense that should be included in the interest claw-back penalty calculations should be the sum of interest on debt, other interest and the difference between the accounting and tax amounts of the amortization of debt discount. Board staff submitted that the tax amount must be added to interest expense since the interest claw-back true-up is a tax value true-up based on tax returns. Board staff also submitted that AFUDC, also known as capitalized interest, must be added back to determine the amount of interest to be used in the true-up calculations.

In its reply submission, Enersource noted that in the Combined Proceeding, Barrie Hydro incorporated its true up of the tax amortization of debt issue costs in TAXREC2. Enersource applied the same methodology in its current application, such that the proposed refund includes the benefit of this true-up for ratepayers.

Enersource also noted that it used the same methodology as Barrie Hydro and EnWin to calculate the interest claw-back as approved by the Board in Excel sheet TAXCALC of their respective SIMPIL models. Enersource agreed that the benefit of the tax amortization should be returned to ratepayers, but it does not agree that the ratepayers should receive the benefit twice. As such, Enersource disagreed that the difference between the accounting and the tax amortization of debt discount should be included in the excess interest true-up calculations. Enersource proposed to maintain the tax amortization of the debt issue costs in TAXREC2, as a benefit to ratepayers, but exclude it from the deemed interest claw-back calculation.

Bad Debts Expense Added back in 2001 SIMPIL Model

Enersource entered bad debt expense of $627,402 in the 2001 SIMPIL model related to accounts receivable that were determined to be unrecoverable during the fourth quarter 2001. The Ministry of Finance denied the deduction in Enersource's 2001 tax returns.

[6] EB-2011-0174, Decision and Order, December 22, 2011, pages 9-10

Board staff noted that it is important to remember that costs incurred and income earned before October 1, 2001 were not subject to income tax PILs and were not deductible in the period after September 30, 2001. If the sales and resultant income were not taxable because they took place in the period before Enersource became subject to PILs, then the expenses related to writing off those sales would not be deductible for tax purposes. Board staff submitted that the bad debts expense should be moved to sheet TAXREC3 in the 2001 SIMPIL model so that the costs do not true up to the ratepayers.

In its reply submission, Enersource agreed that the bad debts should not true up to ratepayers and filed a revised 2001 SIMPIL model.

Consistent with the Board’s approach in Hydro One Brampton (EB-2011-0174), the Board finds that the components which will comprise interest expense for purposes of the true-up calculations based on Enersource’s evidence in this case are: interest on debt and other interest consisting of bank overdraft interest, amortization of debt issue costs and the effect of rounding.

Interest Expense Components	**2001**	**2002**	**2003**	**2004**	**2005**
Interest on Debt	4,454,000	18,241,000	18,241,000	18,241,000	18,241,000
Bank overdraft interest		78,989	484		
Rounding		37	162	-18	-293
Amortization of debt issue costs	111,694	433,584	433,584	433,584	433,584
	4,565,694	18,753,610	18,675,230	18,674,566	18,674,291

The Board is not persuaded that Enersource’s submission is consistent with prior Board determinations and previous regulatory guidance. As such, the Board is also of the view that it is appropriate that the difference between the accounting and the tax amortization of debt discount be excluded in the excess interest true-up calculations.

The Board notes that Enersource has agreed with Board staff that the bad debts expense should be moved to sheet TAXREC3 in the 2001 SIMPIL model so that the costs do not true up to ratepayers.

The Board has calculated that the credit balance to be refunded to ratepayers after including the findings in this Decision and Order in Enersource’s models is $1,743,408.

The Board approves the disposition of Account 1562 over a one year period, May 1, 2012 to April 30, 2013.

For accounting and reporting purposes, the approved balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the Accounting Procedures Handbook for Electricity Distributors. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

Review and Disposition of Lost Revenue Adjustment Mechanism

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on March 28, 2008 outline the information that is required when filing an application for LRAM or SSM.

Enersource sought to recover a total LRAM claim of $856,957, including carrying charges, over a one-year period. The lost revenues include the persisting impacts of 2005-2009 CDM programs in 2010 and lost revenues from 2010 CDM programs in 2010.

<u>Persisting Impacts of 2005-2008 Programs in 2010</u>

In its submission, Board staff noted that Enersource's rates were last rebased in 2008. Board staff noted that the CDM Guidelines state the following with respect to LRAM claims:

> Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time[7].

In cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically

[7] Section 5.2: Calculation of LRAM, Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037)

because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application is appropriate.

In response to Board staff interrogatory #7(e), Enersource indicated that in its 2008 cost of service application it proposed a reduction to forecast throughput in the 2008 test year attributable to the effects of CDM. Enersource also indicated that the proposed reduction to the 2008 forecast throughput was eliminated in the approved Settlement Agreement. Board staff noted that the fact that an outcome of a Settlement Agreement changes the quantum of the overall load forecast as originally filed does not necessarily mean that no CDM effects are imputed into that load forecast. Board staff noted that Enersource may want to highlight in its reply whether the issue of an LRAM application was addressed in the Settlement Agreement accepted by the Board.

In the absence of the above information, Board staff did not support the recovery of the persisting lost revenues from 2005, 2006, 2007, and 2008 CDM programs in 2010 as these amounts should have been built into Enersource's last approved load forecast.

VECC submitted that energy savings from Enersource's CDM programs deployed between 2005 and 2008 are not accruable in the year 2010 as these savings should have been incorporated in the 2008 load forecast at the time of rebasing.

<u>Persisting Impacts of 2009 Programs and Impacts of 2010 Programs in 2010</u>

Board staff noted that Enersource has not collected the lost revenues associated with CDM programs delivered in 2009 and 2010 in 2010, a year in which Enersource was under IRM. Board staff supported the approval of 2009 lost revenues persisting in 2010 and 2010 lost revenues that were the result of 2010 CDM programs, as these lost revenues took place in an IRM year and Enersource did not have an opportunity to recover these amounts.

VECC supported the approval of lost revenues in 2010 from 2009 persistent results in 2010 and 2010 CDM program results in 2010, as these claims occurred post-rebasing and have not been claimed.

In its reply submission, Enersource noted that in its most recent rebasing, that is, its 2008 rates application (EB-2007-0706), it expressly did not include CDM savings. The Settlement Agreement stated that: "…Enersource expects that any 2008 Test Year lost revenue attributable to CDM will be eligible for recovery through the Lost Revenue Adjustment Mechanism and that this issue will be dealt with through a future application."[8]

Enersource noted that Board staff's position that Enersource should not be entitled to recover persistent CDM savings is inconsistent with the Board's past practice. Specifically, the Board did approve the persistence of savings resulting from CDM programs from 2005, 2006, 2007 and 2008 CDM in both 2008 and 2009, subsequent to Enersource's rebasing in 2008, in which CDM savings were explicitly removed from the load forecast.

Enersource noted that it is amenable to revising its LRAM claim to incorporate adjustments arising from responses to interrogatory requests, including the utilization of the most recent OPA assumptions, dated November 15, 2011, as follows:

Original LRAM Claim	$856,957	
Updated to reflect OPA Nov 15 info	+5,680	(per response to Staff IR 7 (B))
Updated to reflect LED adjustment	-2,298	(per response to VECC IR 2 [b])
Revised LRAM Claim	**$860,339**	

The Board will approve Enersource's revised LRAM claim of $860,339, representing lost revenues arising from the persistence of 2005-2009 CDM programs in 2010 and lost revenues from 2010 CDM programs in 2010. In general, the Board is of the view that LRAM is accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. However, as set out in the Settlement Agreement and the transcript from the oral hearing in EB-2007-0706, in which the Settlement Agreement was accepted by the Board, it is apparent that the intent was to remove the CDM effects from the load forecast and defer consideration of those CDM effects to a future LRAM proceeding. As such, the Board is of the view that it is appropriate to deviate from the 2008 CDM Guideline and approve the LRAM recovery sought by Enersource in this application. The Board approves a one year disposition period, May 1, 2012 to April 30, 2013.

[8] EB-2007-0706, Settlement Agreement, Page 12

Smart Meter Funding Adder ("SMFA")

In its application, Enersource requested the Board's approval to implement a SMFA of $0.77 per metered customer per month to replace the current Board-approved SMFA of $2.12 per metered customer per month.

Enersource's rationale for the continuation of a 2012 SMFA is the result of delays encountered in completing the deployment of smart meters. Enersource completed 98% of its deployment as of December 31, 2010, but, due to unforeseen issues, primarily related to issues pertaining to the need for 1,506 600 volt meters and the additional acquisition of 300 residential meters, Enersource expects smart meter deployment to be completed in the first quarter of 2012.[9] The 300 residential meters represent outstanding installations that are the result of customer refusals, access issues and physical obstructions, including fences, and hazardous meter bases[10].

The 600 volt meters present challenges due to the location of the meters (i.e. inside metal cabinets) which has posed challenges with wireless connection for reading of interval data.

Enersource forecasts that an additional $950,000 for capital investments is needed which relates to the 1,506 600 volt meters and the acquisition of the 300 additional residential meters mentioned above.

Board staff submited that the Board may wish to consider continuance of the SMFA with a specific termination date. Board staff noted that Enersource has requested that the SMFA be extended to April 30, 2013. Enersource is expected to rebase its rates through a cost of service application for the 2013 rate year. Given that Enersource has not yet completed the deployment of its smart meters and consequently still has remaining deployment costs to incur, Board staff submitted that Enersouce's request is reasonable.

Board staff is of the view that establishing a termination date of April 30, 2013 for the SMFA should give Enersource enough time to complete its smart meter program, including TOU implementation.

Board staff noted that it would prefer a termination date for the SMFA of December 31,

[9] EB-2011-0100, Application, Tab 4, Page 2
[10] EB-2011-0100, Interrogatory Responses, #6(B)

2012. Board staff requested that, in its reply submission, Enersource indicate to the Board whether it intends to seek a January 1 effective date for its 2013 rates. If Enersource is planning to request a January 1 effective date for 2013 rates, Board staff agreed that it was appropriate for Enersource not to assume that this would be approved by the Board; however, the Board may wish to consider this factor in its Decision.

In its reply submission, Enersource indicated that it is intending to seek a January 1 effective date for its 2013 rates. Enersource noted that it is in agreement with Board staff's suggestion to implement a termination date for the SMFA of December 31, 2012, and will incorporate the final amounts in its smart meter prudence review as part of its 2013 cost of service rebasing application.

The Board will not approve the continuation of the SMFA beyond the current expiry of April 30, 2012. The Board is of the view that the relevant metric to consider with respect to whether it is appropriate to extend a SMFA is the date at which smart meter deployment was or will be substantially completed. In this case, smart meter deployment was 98% complete on December 31, 2010. The SMFA was designed to fund the prospective deployment of smart meters with minimum functionality and was not intended to be compensatory. The Board notes that the net remaining cost for smart meters is approximately $950,000, of a total capital budget for smart meters of approximately $29,500,000. The Board believes that the current expiry date of the SMFA best aligns the interests of ratepayers and the utility, by balancing potential rate volatility with the need to ensure that monies collected from ratepayers serve the intended purpose.

Rate Model

With this Decision, the Board is providing Enersource with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2011 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Enersource's new distribution rates shall be effective May 1, 2012.

2. Enersource shall review the draft Tariff of Rates and Charges set out in Appendix A. Enersource shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision.

3. If the Board does not receive a submission from Enersource to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this order will become final effective May 1, 2012, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2012. Enersource shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Enersource to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Enersource and will issue a final Tariff of Rates and Charges.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Enersource shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to Enersource any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Enersource shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0100,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, April 19, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2011-0100

DATED: April 19, 2012

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.87
Distribution Volumetric Rate	$/kWh	0.0119
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0022)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kWh	(0.0011)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kWh	(0.0004)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM)		
Recovery (2012) – effective until April 30, 2013	$/kWh	0.0003
Rate Rider for Tax Changes – effective until April 30, 2013	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0057

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	39.93
Distribution Volumetric Rate	$/kWh	0.0116
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0022)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kWh	(0.0011)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kWh	(0.0004)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM)		
Recovery (2012) – effective until April 30, 2013	$/kWh	0.0002
Rate Rider for Tax Change – effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

SMALL COMMERCIAL AND UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is either metered or unmetered. While this customer class includes existing metered customers, metered customers are no longer added to this customer class. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer and will be agreed to by Enersource Hydro Mississauga Inc. and the customer and may be subject to periodic monitoring of actual consumption. Eligible unmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge for metered account	$	10.69
Service Charge for Unmetered Scattered Load account (per connection)	$	10.69
Distribution Volumetric Rate	$/kWh	0.0195
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014		
Applicable only for Non-RPP Customers	$/kWh	(0.0022)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kWh	(0.0012)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kWh	(0.0009)
Rate Rider for Tax Changes – effective until April 30, 2013	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

GENERAL SERVICE 50 to 499 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	69.86
Distribution Volumetric Rate	$/kW	4.2044
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	(0.7339)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kW	(0.3693)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kW	(0.0775)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0281
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0626)
Retail Transmission Rate – Network Service Rate	$/kW	2.6160
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0283
Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.6160
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0283

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0100

GENERAL SERVICE 500 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,538.27
Distribution Volumetric Rate	$/kW	2.0981
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	(0.9425)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kW	(0.4696)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kW	(0.0657)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2013	$/kW	0.0111
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0494)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5309
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9847

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13,856.90
Distribution Volumetric Rate	$/kW	2.9225
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014 Applicable only for Non RPP Customers	$/kW	(1.2714)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kW	(0.6324)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kW	(0.0635)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2013	$/kW	0.0035
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.0502)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7007
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1197

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

STANDBY DISTRIBUTION SERVICE CLASSIFICATION

This classification refers to an account that requires Enersource Hydro Mississauga to provide distribution service on a standby basis as a back-up supply to an on-site generator. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

A Standby Service Charge will be applied for a month where standby power is not provided. The applicable rate is the approved Distribution Volumetric Rate of the applicable service class and is applied to gross metered demand or contracted amount, whichever is greater. A monthly administration charge of $200, for simple metering arrangements, or $500, for complex metering arrangements, will also be applied.

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.34
Distribution Volumetric Rate	$/kW	10.2587
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until January 31, 2014		
Applicable only for Non RPP Customers	$/kW	(0.7714)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until January 31, 2014	$/kW	(0.3874)
Rate Rider for Disposition of Accounts 1521 and 1562 (2012) – effective until April 30, 2013	$/kW	(0.2674)
Rate Rider for Tax Change – effective until April 30, 2013	$/kW	(0.2253)
Retail Transmission Rate – Network Service Rate	$/kW	1.8116
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4666

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Request for other billing information	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Credit reference/credit check (plus credit agency costs – General Service)	$	25.00
Income tax letter	$	15.00
Returned cheque (plus bank charges)	$	12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential)	$	20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	10.00
Special meter reads	$	30.00
Interval meter request change	$	40.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	9.00
Disconnect/Reconnect at meter - during regular hours	$	20.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Temporary service install and remove – overhead – no transformer	$	400.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0360
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0256
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045