Schedule 1

DISTRIBUTION LICENCE

Electricity Distribution Licence

ED-2004-0420

PowerStream Inc.

Valid Until

August 29, 2024

Original signed by

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Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: August 30, 2004
Date of Amendment: April 6, 2006 (effective May 1, 2006)
Date of Amendment: February 27, 2008
Date of Amendment: March 31, 2009
Date of Amendment: March 16, 2010
Date of Amendment: November 12, 2010
Date of Amendment: March 8, 2012

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1 Definitions

In this Licence:

“**Accounting Procedures Handbook**” means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

“**Act**” means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

“**Affiliate Relationships Code for Electricity Distributors and Transmitters**” means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

“**Conservation and Demand Management**” and “**CDM**” means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

“**Conservation and Demand Management Code for Electricity Distributors**” means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

“**distribution services**” means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

“**Distribution System Code**” means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

“**Electricity Act**” means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

“**Licensee**” means PowerStream Inc.

“**Market Rules**” means the rules made under section 32 of the Electricity Act;

“**Net Annual Peak Demand Energy Savings Target**” means the reduction in a distributor’s peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

“**Net Cumulative Energy Savings Target**” means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

“**OPA**” means the Ontario Power Authority;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee’s distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor’s distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee’s service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee’s Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee’s Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The Licensee shall:

a) immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee’s premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on August 30, 2004 and expire on August 29, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 95.570 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 407.340 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule, in conjunction with Appendix B specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Town of Markham as of January 1, 1979.

2. The service area is co-terminus with the City of Vaughan municipal boundary pursuant to the Regional Municipality of York Act, R.S.O. 1990, R.18, with the exception of an area two lots north of King-Vaughan Rd. abutting 7th Concession of the Town of King, as detailed in the parcel lot descriptions noted in Appendix B.

3. The Town of Richmond Hill as of January 1, 1979, with the exception of the boundary along Bathurst St, two lots north of King-Vaughan Rd. to Bloomington Rd., noted in Appendix B.

4. The Town of Aurora as of January 1, 1979, with the exception of the boundary along Bathurst St, seven lots north of Bloomington Rd. to two lots north of St. John's Sideroad, noted in Appendix B.

5. Lands located 45m south of the center-line of Castlemore Rd and 37.5m west of the center-line of Highway 50 in the City of Brampton.

6. City of Barrie Service Area:

   Within the municipal boundary of the City of Barrie as detailed firstly in Schedules A and B to the Barrie-Innisfil Annexation Act, 1981, secondly in the Schedule to the Barrie-Vespra Annexation Act, 1984 and thirdly as shown on Reference Map Document Number 4884 included on page 4 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

7. Community of Bradford West Gwillimbury Service Area:

   Within the Community of Bradford West Gwillimbury as detailed firstly as the "Expansion Service Area" in Schedule 'B' and 'C' to the Corporation of the Town of Bradford-West Gwillimbury By-law 95-048 dated September 11, 1995, secondly the portions of the Hydro One letter pertaining to Bradford-West Gwillimbury dated November 27, 2003 and thirdly as shown on Reference Map Document Number 4993 included on page 5 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

8. Community of Thornton Service Area:

   Within the Community of Thornton as detailed firstly in the Thornton Settlement Area in accordance with Schedule “A” of the Official Plan of the Township of Essa as approved by the County of Simcoe, April 22, 2003 and secondly as shown on Reference Map Document Number 5009 included on page 6 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board, excluding the following municipal addresses:

   - #’s 6, 8, 10, 12, 19, 21, 23, 25, 27, 28, 29, 30, 31, 32, 33, 34 and 35 Earl’s Court;

- # 4520 Robert Street (or County Road 21 Pt.16 Concession11);
- all residential lots fronting onto Jamieson Court from Thornton Ave to the cul-de-sac dead end;
- #'s 218, 219, 220, 221, 222, 223, 224, 225, 226, 227, 228, 229, 230, 231, and 232 Thornton Avenue;
- all residential lots fronting onto Lennox Court from Spence Avenue to the cul-de-sac dead end;
- all residential lots fronting onto Spencer Avenue except # 221 Spencer Avenue from Thornton Avenue to North Ridge Road;
- all residential lots fronting onto North Ridge Road except #'s 204 and 205 from Camilla Crescent to Spencer Avenue.

9. Community of Alliston Service Area:

   Within the Community of Alliston as detailed firstly as the “Alliston Urban Area Expansion” in Schedule ‘A’ to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled “H.E.C. Service Area Expansion By-Law”) and secondly as shown on Reference Map Document Number 5720 included on page 7 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board, excluding the consumer located at 4700 Tottenham Road. 2011 – to include lands as described in Proposed Draft Plan of Subdivision of Belterra Estates, to include Part of Lots 12 &13, Concession 14 and Parts of Lots 12 & 13, Concession 15, file number NT-T03002 under the Corporate Township of Tecumseh. In effect it will include lands east of the current border to include the new subdivision by Cable Bridge Enterprises Inc. (Belterra Estates).

10. Community of Beeton Service Area:

    Within the Community of Beeton as detailed firstly as the “Beeton Urban Area Expansion” in Schedule ‘A’ to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled “H.E.C. Service Area Expansion By-Law”) and secondly as shown on Reference Map Document Number 4982 included on page 8 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

11. Community of Tottenham Service Area:

    Within the Community of Tottenham as detailed firstly as the “Tottenham Urban Area Expansion” in Schedule ‘A’ to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled “H.E.C. Service Area Expansion By-Law”) and secondly as shown on Reference Map Document Number 5013 included on page 9 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board. It is noted that the “Beeton Creek” referenced in this schedule is technically a tributary to the actual Beeton Creek. The location of this tributary creek is shown on the Reference Map and it is to the east of the former Village of Tottenham.

12. Community of Penetanguishene Service Area:

    Within the Community of Penetanguishene as detailed firstly as the “Boundary Expansion Agreement” or “Annexation Transfer Agreement” dated December 31, 1998 between the former Ontario Hydro and the Penetanguishene Hydro-Electric Commission and secondly as shown on Reference Map Document Number 5001 included on page 10 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

1. Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

APPENDIX A MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the

IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

 i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

 ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

 i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

APPENDIX B LAND DESCRIPTIONS

No.	Area	Legal Description	No.	Area	Legal Description
1	Vaughan	PT LOT 2, CON 7, PTS 6 & 8, 65R24532; KING ; T/W R216549; S/T EASE OVER PT 6, 65R24532 AS IN A24558A AND RENEWED BY R610943.	17	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING
2	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	18	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING
3	Vaughan	PT LT 2 CON 6 KING AS IN A55205A EXCEPT PTS 1 & 2 65R18259 ; KING	19	Richmond Hill	PT LT 2 CON 2 KING; PT LT 3 CON 2 KING AS IN B16975B, B19261B & A29730A EXCEPT PTS 4 & 5 65R14738 & PTS 8 & 9 65R531 ; KING
4	Vaughan	PT LT 2 CON 6 KING AS IN A55205A EXCEPT PTS 1 & 2 65R18259 ; KING	20	Richmond Hill	LOT 5, CONCESSION 2, KING
5	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	21	Richmond Hill	PT LT 3 CON 2 KING PT 2 65R5820 ; KING
6	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	22	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
7	Vaughan	PT LT 3 CON 6 KING AS IN R184760 ; KING	23	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
8	Vaughan	PT LT 3 CON 6 KING AS IN R184760 ; KING	24	Vaughan	LOT 2, CONCESSION 2, KING TWNSHP
9	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	25	Vaughan	PT LT 5 CON 2 KING PT 2 65R599 ; KING
10	Richmond Hill	PT LT 3 CON 2 KING PT 2 65R5820 ; KING	26	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
11	Richmond Hill	LOT 7, CONCESSION 2, KING	27	Vaughan	PT LT 5 CON 2 KING PT 2 65R599 ; KING
12	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING	28	Aurora	PT LT 14 CON 2 KING AS IN R180958 EXCEPT PT 13 EXPROP PL R233113 ; KING ; SUBJECT TO EXECUTION 95-05877, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 95-06771, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 96-02878, IF ENFORCEABLE. ;
13	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING	29	Aurora	PT LT 14 CON 2 KING AS IN KI25920 EXCEPT PT 11 EXPROP PL R233113 ; KING ; SUBJECT TO EXECUTION 96-06008, IF ENFORCEABLE. ;
14	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	30	Aurora	PT LT 14 CON 2 KING PT 1 65R2712 ; KING
15	Richmond Hill	PT LT 2 CON 2 KING; PT LT 3 CON 2 KING AS IN B16975B, B19261B & A29730A EXCEPT PTS 4 & 5 65R14738 & PTS 8 & 9 65R531 ; KING	31	Aurora	PT LT 14 CON 2 KING PT 1 65R2712 ; KING
16	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	32	Aurora	PT LT 15 CON 2 KING PT 2 65R8504 ; KING

No.	Area	Legal Description	No.	Area	Legal Description
33	Aurora	PT LT 15 CON 2 KING PT 1 65R8504 ; KING	51	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING
34	Aurora	PT LT 15 CON 2 KING AS IN B47985B EXCEPT PT 8 EXPROP PL R233113 ; KING	52	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING
35	Aurora	PT SE1/4 LT 16 CON 2 KING PTS 2 & 3 65R10629; T/W R439940 ; KING	53	Aurora	PT LT 24 CON 2 KING AS IN R629682 T/W R137178 ; KING
36	Aurora	PT SE1/4 LT 16 CON 2 KING PTS 2 & 3 65R10629; T/W R439940 ; KING	54	Aurora	PT LT 24 CON 2 KING AS IN R629682 T/W R137178 ; KING
37	Aurora	PT NE1/4 LT 16 CON 2 KING PT 2 65R15552 ; KING	55	Aurora	PT LT 24, CON 2, (KING) IN R662420 EXCEPT PTS 1 & 2, PL 65R29165, KING
38	Aurora	PT NE1/4 LT 16 CON 2 KING; PT LT 17 CON 2 KING; PT LT 18 CON 2 KING PTS 1, 3 65R15552 ; KING	56	Aurora	LOT 16, CONCESSION 2, KING
39	Aurora	PT NE1/4 LT 16 CON 2 KING; PT LT 17 CON 2 KING; PT LT 18 CON 2 KING PTS 1, 3 65R15552 ; KING	57	Aurora	PT LT 15 CON 2 KING AS IN R166067 EXCEPT R242869 ; KING
40	Aurora	PT LT 18 CON 2 KING PT 1 65R5395 ; KING	58	Aurora	PT LT 15 CON 2 KING AS IN R400615 ; KING
41	Aurora	PT LT 18 CON 2 KING AS IN R602840 ; KING	59	Aurora	PT SE1/4 LT 16 CON 2 KING PT 1 65R3379; T/W R145038 ; KING
42	Aurora	LOT 18, CONCESION 2, KING TWSHP	60	Aurora	PT LT 14 CON 2 KING AS IN B50839B EXCEPT PTS 10 & 12 EXPROP PL R233113; PT LT 15 CON 2 KING AS IN B27240B EXCEPT PT 2 65R9307; T/W R406638 ; KING
43	Aurora	PT LT 18 CON 2 KING PT 1 65R13476 ; KING	61	Aurora	PT LT 14 CON 2 KING AS IN B50839B EXCEPT PTS 10 & 12 EXPROP PL R233113; PT LT 15 CON 2 KING AS IN B27240B EXCEPT PT 2 65R9307; T/W R406638 ; KING
44	Aurora	PT LT 18 CON 2 KING PT 1 65R13476 ; KING	62	Aurora	PT LT 15 CON 2 KING PTS 2, 3 & 4 65R17617; S/T R660937; T/W R660070. ; KING
45	Aurora	PT LT 18 CON 2 KING PT 1 65R609 EXCEPT PT 8 EXPROP PL R233114 ; KING	63	Aurora	PT LT 15 CON 2 KING PT 5 65R17617; T/W R660938 ; KING
46	Aurora	LOT 19, KING TWSHP	64	Aurora	NE1/4 LT 16 CON 2 KING PTS 1,2 65R3343; SE1/4 LT 16 CON 2 KING PTS 3,4 65R3343 ; KING
47	Aurora	LOT 19, KING TWSHP	65	Aurora	PT LT 13 CON 2 KING AS IN R306307 S/T INTEREST IN KI22671, S/T DEBTS IN R306307 ; KING
48	Aurora	PT LT 20 CON 2 KING PT 1 65R1245 EXCEPT PT 11, EXPROP PL R233114 ; KING	66	Aurora	PT SE1/4 LT 16 CON 2 KING PT 1, 65R20034; KING
49	Aurora	PT LT 21 CON 2 KING; PT LT 22 CON 2 KING AS IN B2661B EXCEPT PT 4 B33711B; DESCRIPTION MAY NOT BE ACCEPTABLE IN THE FUTURE AS IN B2661B ; KING	67	Aurora	PT SE1/4 LT 16 CON 2 KING PT 3, 65R20034; T/W R720871 ; KING ; SUBJECT TO EXECUTION 96-00974, IF ENFORCEABLE
50	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING	68	Aurora	LOT 21, CONCESSION 2, KING TWNSHP

Schedule 2

DRAFT ISSUES LIST

PowerStream Inc. proposes that the Issues List be drafted as the rate review proceeds.

Schedule 3

DECISIONS / PROCEDURAL ORDERS / MOTIONS / CORRESPONDENCE

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2011-0005

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 PowerStream 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

PowerStream Inc. ("PowerStream"), a licensed distributor of electricity, 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 PowerStream charges for electricity distribution, to be effective May 1, 2012. PowerStream operates two separate rate zones, the North (Barrie) rate zone and the South rate zone.[1]

PowerStream 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*

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[1] The North rate zone consists of the former Barrie Hydro service territory (Alliston, Barrie, Beeton, Bradford West Gwilimbury, Penetanguishene, Thornton and Tottenham). The South rate zone consists of the former PowerStream Inc. service territory (Aurora, Markham, Richmond Hill and Vaughan).

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, PowerStream 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 PowerStream’s rate application was given through newspaper publication in PowerStream’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 PowerStream’s proposed revenue-to-cost ratio adjustments and its request for lost revenue adjustment mechanism (“LRAM”) recoveries. 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 PowerStream’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 Charge;
- 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; and
- Review and Disposition of Lost Revenue Adjustment Mechanism (“LRAM”).

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 PowerStream 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.

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.

PowerStream’s application identified a total tax savings of $3,031,921 for the South rate zone resulting in a shared amount of $1,515,961 to be refunded to rate payers. PowerStream’s application also identified a total tax savings of $1,124,105 for the North rate zone resulting in a shared amount of $562,052 to be refunded to rate payers.

Board staff submitted that PowerStream completed the Tax-Savings Workform for both rate zones with the correct rates and amounts reflecting previous Board decisions. The Board approves the disposition of the shared tax savings of $1,515,961 for the South rate zone and $562,052 for the North rate zone over a one year period (i.e. May 1, 2012 to April 30, 2013) and the associated rate riders for all customer rate classes. The Board notes that the calculation of shared tax savings is consistent with the Board's approach.

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	$0.80 per kW
Transformation Connection Service Rate	$1.86 per kW

Board staff had no concerns with the data supporting the RTSR Workform proposed by PowerStream for both rate zones. The Board finds that the 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.

In December 2008, the Board approved the amalgamation of PowerStream Inc. and Barrie Hydro Distribution Inc. (EB-2008-0335). In the current application, PowerStream noted that it continued to receive separate invoices from the IESO for each of its rate zones in 2009. As of 2010, the amalgamated PowerStream began to receive a single invoice from the IESO for both rate zones. PowerStream stated that as a result of the change in invoicing from the IESO it is unable to separate the Group 1 Retail Settlement Variance Account ("RSVA") balances by rate zone for 2010. PowerStream noted that it continues to track accounts 1590 and 1595 separately by rate zone.

In order to determine if the disposition threshold had been exceeded, PowerStream computed three separate thresholds for Group 1 RSVA balances: (i) the claim (in $ per kWh) for RSVA balances up to December 31, 2009 and accounts 1590 and 1595 up to December 31, 2010, in the South rate zone, (ii) the claim (in $ per kWh) for balances up to December 31, 2009 and accounts 1590 and 1595 up to December 31, 2010, in the North rate zone, and (iii) the claim (in $ per kWh) for the overall RSVA balances in both rate zones from January 1, 2010 to December 31, 2010, excluding accounts 1590 and 1595. PowerStream then added the claim per kWh for each individual rate zone with the overall claim per kWh for RSVA balances in 2010 to perform the threshold test for each rate zone.

Board staff submitted that PowerStream's approach to performing the threshold test was inconsistent with the spirit of the EDDVAR Report. On page 10 of the EDDVAR Report, the Board states that the "disposition threshold level should enhance the distributor's ability to manage its cash flow." Board staff was of the view that a distributor's cash flow is best reflected at the utility (overall) level and not within each individual rate zone. Accordingly, Board staff was of the view that a single threshold test should be applied to the total Group 1 RSVA balances combined across all rate zones.

Board staff noted that even with the revised approach, the threshold is not exceeded. Board staff therefore had no issue with PowerStream's proposal to not dispose of the balances in its Group 1 Accounts.

The Board agrees with the submission of staff that the EDDVAR threshold test should be applied to the combined balances of PowerStream North and PowerStream South to be consistent with EDDVAR. The Board notes that the EDDVAR threshold has not been exceeded on a combined basis. Accordingly, no disposition of Group 1 accounts is required at this time.

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.

PowerStream requested the disposition of a residual credit balance of $14,007 as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012 over a one year period. In the Manager's Summary of its Application, PowerStream noted that it did not track balances in Account 1521 separately by rate zone. The credit balance of $14,007 represented the total combined balance for both PowerStream rate zones. PowerStream proposed to dispose of the balance in Account 1521 over a one-year period using a variable rate rider uniform to both rate zones. Balances were allocated to each class using the overall billed kWh for each class without regard to rate zone.

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 noted that the uniform rate riders proposed by PowerStream resulted in zero values for some classes when rounded to four decimal places (for energy-based kWh rate riders) and two decimal places (for demand-based kW rate riders). Board staff submitted that the $14,007 credit balance should be recorded in Account 1595 for future disposition. PowerStream did not object to Board staff's proposal to record the SPC balance in Account 1595 for future disposition.

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 of $14,007. As per the Filing Requirements, the Board directs PowerStream to record the SPC balance in variance Account 1595 for future disposition. 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 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. In its decision and order, the Board approved a $565,583 credit balance for Barrie Hydro (North rate zone) including carrying charges calculated to April 30, 2012.

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, "[e]ach 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)."[2]

On August 25, 2011, PowerStream filed a letter indicating that it would not be filing for disposition of the balance in account 1562 for the South rate zone in its 2012 IRM application. On October 12, 2011, the Board issued a letter indicating that it accepted PowerStream's rationale for deferring the disposition of balances in account 1562 for the South rate zone to its 2013 cost of service rate application.

PowerStream applied in the current proceeding to dispose of the Board approved credit balance in Account 1562 of $565,583 for its North rate zone (former Barrie Hydro) including carrying charges projected to April 30, 2012 over a one-year period. PowerStream allocated the amount in Account 1562 based on the distribution revenue approved in Barrie Hydro's last cost of service proceeding. PowerStream noted that the load forecasted for Barrie Hydro's 2008 test year included forecasted revenue for the newly created Large Use class. PowerStream explained that the Large Use class did not exist at the time the balances were incurred and, as such, did not allocate any of the recovery to that class.

Board staff took no issue with PowerStream's proposal to dispose of balances in Account 1562 for the North rate zone nor with the adjustment for the Large Use class.

The Board approves the disposition of a credit balance of $565,583 for PowerStream's

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

North rate zone (former Barrie Hydro), representing principal as at December 31, 2006 and interest to April 30, 2012, over a one year period from May 1, 2012 to April 30, 2013. The Board approves the allocation and recovery methodology proposed by PowerStream as they are consistent with the decision arising from the Combined PILs proceeding.

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 (“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.

PowerStream requested the recovery of an LRAM claim of $554,020, including carrying charges calculated to April 30, 2012, for the North rate zone. PowerStream’s LRAM claim consists of the effect of 2009 programs in 2009-2011, the effects of 2010 programs in 2010 and 2011 and the persisting effects of 2007-2008 programs in 2009-2011. PowerStream proposed to use forecast 2012 billing determinants to calculate the LRAM rate riders and to recover amounts over a one-year period.

Board staff submitted that it did not support recovery of the requested persisting lost revenues from 2007 and 2008 CDM programs in 2009 through 2011 as these amounts should have been incorporated into PowerStream’s last approved load forecast for the North rate zone. Board staff supported the recovery of 2009 and 2010 programs in 2009 and 2010 as the lost revenues took place during IRM years and PowerStream did not have an opportunity to recover those amounts. Board staff submitted that it was premature to consider any persisting lost revenues from programs in 2011.

Similarly, VECC submitted that the LRAM claim approved by the Board should be adjusted to include only lost revenue in 2009 and 2010 from the impact of CDM programs delivered in 2009 and 2010. VECC did not support recovery of persisting lost revenues in 2011. VECC submitted that PowerStream should be using a Board-approved forecast or historical data in calculating its LRAM rate riders. VECC noted that it believed PowerStream's most recent historical data is more representative of current load and should be used.

PowerStream noted that the load forecast underpinning 2008 distribution rates for Barrie Hydro did not include load reductions due to any of its CDM programs. In its 2008 load forecast, Barrie Hydro used the 2004 normal average use per customer ("NAC") by customer class provided to it by Hydro One. PowerStream noted that the 2004 NAC data could not include the impact of 2007 and 2008 CDM programs. PowerStream also noted that the decision for Barrie Hydro's last cost of service application (EB-2007-0746) was made before the CDM guidelines were issued. PowerStream submitted that it is eligible for the persisting lost revenues attributable to its 2007 and 2008 CDM programs in the North rate zone.

In its reply submission, PowerStream stated that using the best estimate of the billing determinants for the period in which rate riders will be charged will provide a better matching of recoveries to the approved amount for each rate class. PowerStream stated that using forecasted 2012 billing determinants is the most appropriate way to calculate the LRAM rate riders and noted that the Board had approved the use of similar billing determinants in PowerStream's prior IRM application (EB-2010-0110).

The Board will approve a total LRAM claim for the North rate zone of a debit balance of $357,381 including carrying charges to April 30, 2012. The Board approves a one year disposition period from May 1, 2012 to April 30, 2013.

Consistent with the Board's findings in EB-2010-0110, the Board is of the view that the 2004 NAC based load forecast underpinning the North rate zone's current rates does not include the impact of Barrie Hydro's CDM programs. The Board also notes that the EB-2007-0746 decision dated March 25, 2008 was issued prior to the CDM Guidelines (EB-2008-0037). The Board therefore approves LRAM for persistence of 2007 and 2008 programs in 2009 and 2010, as Barrie Hydro was under IRM during these years and Barrie Hydro has not otherwise been compensated for lost revenues during this period. The Board also approves an LRAM recovery for the effects of 2009 programs in 2009 and persistence in 2010 and the effect of 2010 programs in 2010.

The Board will not approve LRAM claims associated with 2011, as it is premature to do so and contrary to the 2008 CDM Guidelines.

The Board finds that PowerStream should use the billing determinants approved by the Board in PowerStream's last rebasing application, as this is consistent with the Board's guidelines (Chapter 3 of the Filing Requirements dated June 22, 2011, page 27).

Rate Model

With this Decision, the Board is providing PowerStream 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. PowerStream's new distribution rates shall be effective May 1, 2012.

2. PowerStream shall review the draft Tariff of Rates and Charges set out in Appendix A. PowerStream 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 PowerStream 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, except for the stand by rates which remain interim, effective May 1, 2012, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2012. PowerStream 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 PowerStream 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 PowerStream 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 claim no later than **7 days** from the date of issuance of the final Rate Order.

2. PowerStream 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 PowerStream any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. PowerStream 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-2011-0005,** 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-2011-0005

DATED: March 22, 2012

PowerStream 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-2011-0005

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general 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	$	11.99
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.28
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	0.14
Distribution Volumetric Rate	$/kWh	0.0135
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – 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	0.0027

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

PowerStream 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-2011-0005

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

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.

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	$	28.64
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.01
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	3.37
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024

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

PowerStream 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-2011-0005

GENERAL SERVICE 50 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, 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.

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	$	84.45
Distribution Volumetric Rate	$/kW	3.5036
Low Voltage Service Rate	$/kW	0.0472
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0501)
Retail Transmission Rate – Network Service Rate	$/kW	2.6711
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9731

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

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

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EB-2011-0005

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	$	2,173.63
Distribution Volumetric Rate	$/kW	1.0484
Low Voltage Service Rate	$/kW	0.0558
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0175)
Retail Transmission Rate – Network Service Rate	$/kW	3.1338
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1501

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

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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EB-2011-0005

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is 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 customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. 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)	$	14.32
Distribution Volumetric Rate	$/kWh	0.0087
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027

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

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

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EB-2011-0005

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to 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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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)	$	2.00
Distribution Volumetric Rate	$/kW	9.3917
Low Voltage Service Rate	$/kW	0.0401
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.1458)
Retail Transmission Rate – Network Service Rate	$/kW	2.0412
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8252

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

PowerStream 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-2011-0005

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 operation, 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)	$	0.84
Distribution Volumetric Rate	$/kW	4.8616
Low Voltage Service Rate	$/kW	0.0367
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.1276)
Retail Transmission Rate – Network Service Rate	$/kW	2.0208
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7566

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

PowerStream 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-2011-0005

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

PowerStream 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-2011-0005

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		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	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
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
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary Service install and remove – overhead – no transformer	$	500.00

PowerStream 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-2011-0005

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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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	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility'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	$	15.34
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	1.78
Distribution Volumetric Rate	$/kWh	0.0137
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0006)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kWh	(0.0006)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0054

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

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility'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	$	16.11
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	4.73
Distribution Volumetric Rate	$/kWh	0.0164
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0004)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

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

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE 50 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 expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility'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	$	395.68
Distribution Volumetric Rate	$/kW	1.8393
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0650)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kW	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kW	(0.0705)
Retail Transmission Rate – Network Service Rate	$/kW	2.4897
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8939

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

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE 50 to 4,999 kW TOU SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW and who has an electrical service of at least 600 amps at 600/347 volts or 1600 amps at 208/120 volts. If the customer meets these criteria then an interval meter is required. Further servicing details are available in the utility'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	$	395.68
Distribution Volumetric Rate	$/kW	1.8393
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0650)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kW	0.0020
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kW	(0.0705)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.3052
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5142

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

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than or is expected to be equal to or greater than 5000 kW. Further servicing details are available in the utility'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	$	9,690.24
Distribution Volumetric Rate	$/kW	0.5918
Low Voltage Service Rate	$/kW	0.3886
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0764)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.1192
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5775

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

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

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EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW. As determined by Barrie Hydro Distribution Inc. because of the type of connection or location a meter is not feasible in these situations. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility'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)	$	7.95
Distribution Volumetric Rate	$/kWh	0.0161
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0005)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kWh	(0.0009)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

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

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the utility'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 – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	2.6620

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the utility'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)	$	3.02
Distribution Volumetric Rate	$/kW	11.2961
Low Voltage Service Rate	$/kW	0.2301
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.4780)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kW	(0.1545)
Retail Transmission Rate – Network Service Rate	$/kW	1.9668
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4960

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

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. 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 utility'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	$	5.25

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. 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.

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
Easement Letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – no disconnection	$	15.00
Disconnect/Reconnect at Meter - during Regular Hours	$	30.00
Disconnect/Reconnect at Meter - after Regular Hours	$	185.00
Disconnect/Reconnect at Pole - during Regular Hours	$	185.00
Disconnect/Reconnect at Pole - after Regular Hours	$	415.00
Service Call – customer owned equipment – charge based on time and materials		
Service Call – after regular hours – charge based on time and materials		
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

PowerStream 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-2011-0005

Former Barrie Hydro Distribution Inc. 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	1.0565
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0462
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0128

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 PowerStream Inc. for an order or orders approving or fixing a just and reasonable distribution rates related to Smart Meter deployment, to be effective November 1, 2011.

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Ken Quesnelle
Panel Member

DECISION AND ORDER
(Original November 21, 2011, as corrected December 9, 2011)

PowerStream Inc. ("PowerStream") filed an application with the Ontario Energy Board (the "Board") on June 24, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking final approval for smart meter related costs to the end of April 30, 2011 and other going forward costs.

THE APPLICATION

PowerStream operates two separate rate zones, PowerStream South, (the "legacy service area") and PowerStream North, the Barrie service area. This application pertains to both service areas. The Board assigned the application file number EB-2011-0128.

The Board issued a Notice of Application and Hearing on July 14, 2011. The Vulnerable Energy Consumers Coalition ("VECC") was the only party that sought intervenor status and cost award eligibility. The Board approved VECC as an intervenor and awarded VECC cost eligibility status. Veridian Connections Inc. applied for and was granted observer status.

The Board issued Procedural Order No. 1 on July 14, 2011, which invited submissions on certain evidence for which PowerStream had requested confidential treatment. No submissions were received. The Board issued a Decision on Confideniality on August 17, 2011 approving PowerStream's request to retain the subject information in confidence. In accordance with Procedural Order No. 1, Board staff filed interrogatories ("IRs") on August 17, 2011. VECC filed IRs on August 22, 2011. PowerStream filed its responses on September 9, 2011.

The Board issued Procedural Order No. 2 on September 27, 2011, pursuant to which Board staff filed a submission on October 7, 2011, VECC filed a submission on October 14, 2011 and PowerStream filed its reply submission on October 21, 2011.

The Issues

The following are the key issues raised in the submissions by Board staff and VECC and addressed in this Decision:

- Prudence of documented costs for installed smart meters;
- Inclusion of unaudited actual costs;
- Forecasted costs and the date of disposition;
- Cost allocation methodology; and
- Carrying Charges on OM&A and Amortization.

Prudence of documented costs for installed smart meters

PowerStream seeks recovery of costs associated with 21,725 meters installed in its South rate zone between January 1, 2010 and April 30, 2011 and for 69,393 smart meters installed in its North rate zone from program inception (2006) through April 30, 2011. The costs documented in the Application represent capital costs of approximately $11.2 million in the South rate zone and $11 million in the North rate zone.

PowerStream proposes to recover these costs through two rate riders: (i) a Smart Meter Disposition Rate Rider ("SMDR") and (ii) a Smart Meter Incremental Revenue Requirement Rate Rider ("SMIRR"). The SMDR will recover the difference between the deferred revenue requirement for the installed meters up to the date of disposition and the Smart Meter Funding Adder revenues collected, to date. The SMIRR is designed to recover the annualized incremental revenue requirement for the capital and operating expenses for the installed smart meters going forward. The total amounts proposed for recovery through the SMDR and SMIRR in each rate zone are shown in Table 1.

Table 1 - Total proposed amounts to be recovered from the two riders

Rate zone	SMDR	SMIRR
North	$262,115	$1,724,725
South	$(2,091,164)	$1,342,328

This is the third application filed by PowerStream for a final prudence review of a component of its smart meter deployment program. In 2008, PowerStream received approval for its smart meter costs incurred to December 31, 2007 for its South rate zone as part of a Board-approved settlement agreement (EB-2008-0244). In 2010, PowerStream filed a stand-alone application (EB-2010-0209), in which the Board approved costs incurred in the deployment of 137,356 smart meters in the South rate zone between January 1, 2008 and December 31, 2009. The North rate zone was not part of either of the two previous applications.

PowerStream's audited actual costs showed an average capital cost of $137.43 per meter for meters installed between January 1, 2008 and December 31, 2009, in the South rate zone (EB-2010-0209). PowerStream's documented costs in this application, summarized in Table 2, showed an overall increase in average cost per meter from prior Board approved costs.

Table 2 - Summary of average capital costs per meter installed (includes meter and other capital costs).

Rate Zone	Residential		GS < 50 kW		Total	
	$/meter	# of meters	$/meter	# of meters	$/meter	# of meters
North	$130.51	64,199	$514.24	5,194	$159.24	69,393
South	$311.04	4,470	$570.38	17,255	$517.02	21,725

PowerStream explained that this increase was mainly the result of the mix of meter types covered by the current application. Powerstream stated that, in the South rate zone, the majority of meters installed were non-standard (i.e. 3-phase, network, etc.) meters. The break-down of installed costs per meter type in each rate zone are summarized in Table 3. The average meter costs for standard residential and GS<50 kW meters documented in this application decreased over prior Board approved costs.

Table 3 - Average installed cost per meter (meter installation costs only)

Rate Zone:	**North**			**South**		
Class/Type	**Quantity**	**Installed Cost**	**Cost per meter**	**Quantity**	**Installed Cost**	**Cost per meter**
Residential						
Standard	62,621	$ 6,363,107	$ 101.61	255	$ 25,833	$101.31
400 Amps	518	$ 138,533	$ 267.44	1,020	$271,570	$ 266.25
Network	1,060	$ 295,486	$278.76	3,195	$866,261	$277.34
Total	**64,199**	**$ 6,797,126**	**$ 105.88**	**4,470**	**$ 1,183,664**	**$264.80**
GS<50 kW						
Single Phase	1,429	$ 309,812	$ 216.80	3,081	$ 624,326	$ 202.64
3-phase 120-480V	3,476	$ 1,964,436	$565.14	12,936	$ 7,267,208	$ 561.78
3-phase 600 Volt	289	$ 268,742	$929.90	1,238	$ 1,152,439	$ 930.89
Total	**5,194**	**$ 2,542,990**	**$ 489.60**	**17,255**	**$ 9,043,973**	**$524.14**
TOTAL	**69,393**	**$9,340,116**	**$ 134.60**	**21,725**	**$10,227,637**	**$ 470.78**

PowerStream also noted that following Measurement Canada's approval of a second supplier for 3-phase smart meters, the company was able to secure more favourable pricing for 3-phase smart meters in the fall of 2010. This resulted in a decrease in the average total capital cost per meter from $682.56 to $570.38[1] for GS < 50 kW customers in the South rate zone.

Neither Board staff nor VECC raised any issues with respect to the prudence of the costs documented by PowerStream in the Application.

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[1] Application (EB-2011-0128), page 30, June 24, 2011.

Board Findings

In the Board's prior two decisions on PowerStream's smart meter costs the Board has found the costs to have been prudently incurred. PowerStream has continued with its procurement practices. The company has also demonstrated its market monitoring efforts by securing more favourable pricing as new suppliers became available through Measurement Canada's approval process. No issues have been raised by any of the parties in respect of these costs. The Board finds the audited costs documented in the application to have been prudently incurred.

Inclusion of Unaudited Actual Costs

In its application, PowerStream also provided unaudited actual costs for the period between January 1, 2011 and April 30, 2011, for both rate zones. Board staff took no issue with the nature and quantum of these unaudited actual costs. Staff noted that the unaudited actual costs were comparable to the documented audited actuals and compared favourably to costs approved in PowerStream's prior applications before the Board.

The Notes tab of version 2.0 of the Board's Smart Meter Model states that[2]:

> The Board expects that the majority (i.e. 90% or more) of costs for which the distributor is seeking recovery will be audited. In all cases, the Board expects that the distributor will document and explain any differences between unaudited or forecasted amounts and audited costs.

Board staff noted that the unaudited costs represent more than 10% of the costs documented in the application, but submitted that the unaudited costs represent approximately 10% of the total costs incurred by PowerStream over its smart meter roll out. Board staff submitted that the correct interpretation of the 10% threshold was as a proportion of the overall smart meter deployment costs from program inception to the date of disposition.

VECC noted that 12.36% of costs in the North rate zone and 46.96% of the costs in South rate zone were unaudited in this application. VECC disagreed with Board staff's

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[2] The Board issued this Smart Meter Model, an Excel spreadsheet, to electricity distributors under covering letter on September 13, 2011.

position that the 10% threshold should be applied to the total costs incurred in the smart meter implementation, across all applications. VECC submitted that the 10% threshold should only apply to the current costs that a distributor is seeking to recover.

PowerStream agreed with Board Staff's interpretation of the threshold for unaudited costs. PowerStream also noted that VECC raised no other concerns with the documented costs other than the fact that they are unaudited.

Table 4, below, shows a detailed summary of the costs incurred by PowerStream in their smart meter implementation, across all applications. In its submission, Board staff estimated that approximately 10% of the overall costs incurred in PowerStream's smart meter implementation were unaudited as presented in this application. The more detailed calculation below shows that the actual unaudited costs for both rate zones in this application as a percent of total costs to date is approximately 12%.

Table 4 - Summary of PowerStream's overall smart meter spending

	North Rate Zone	**South Rate Zone**	**Total**
	Capital Costs		
Board approved Capital additions			
EB-2008-0244	$0	$10,121,905	$10,121,905
EB-2010-0128	$0	$18,876,357	$18,876,357
EB-2011-0128 Documented Costs			
Audited	$9,999,761	$6,023,222	$16,022,983
Unaudited actual	$1,050,096	$5,209,014	$6,259,110
	OM&A		
Board approved OM&A			
EB-2008-0244 approved costs	$0	$190,519	$190,519
EB-2010-0128 approved costs	$0	$2,225,937	$2,225,937
EB-2011-0128 Documented Costs			
Audited OM&A	$332,553	$556,953	$889,506

Actual Unaudited OM&A	$148,347	$166,110	$314,457
Projected OM&A (May 1 to December 31, 2011)	$258,765	$451,157	$709,922
Total costs to date (including EB-2011-0209)[3]	**$11,530,757**	**$43,370,017**	**$54,900,774**
Total actual costs in EB-2011-0128	**$10,332,314**	**$6,580,175**	**$16,912,489**
Total unaudited costs in EB-2011-0128[3]	**$1,198,443**	**$5,375,124**	**$6,573,567**
Unaudited costs, as % of total program costs to date	**10%**	**12%**	**12%**
Unaudited costs, as % of costs included in EB-2011-0128	**10%**	**45%**	**28%**

Board Findings

The Board finds the unaudited actual costs documented by PowerStream in the application to be appropriate for recovery. Though PowerStream's documented unaudited costs exceed 10% of total program costs to date by a modest amount, the Board does not believe that the level of unaudited costs in this application is high enough to warrant the additional expense and delay associated with an additional proceeding. The Board notes that no concerns were raised with the unaudited costs, nor were any issues raised with respect to the nature of the costs incurred by PowerStream. On the contrary, Board staff noted that the nature, type and quanta of costs incurred during the unaudited period were consistent with the audited costs in this application. The Board also notes that no costs have been disallowed in prior PowerStream smart meter proceedings covering the South Rate zone, and the Board has considered this fact in reaching its conclusion that it is reasonable in the current circumstances to accept a larger proportion of unaudited costs. With respect to the North Rate zone, the area which has not been reviewed in the past by the Board, the unaudited costs are only 10% of the total costs to date (and of the current application).

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[3] Does not include forecasted OM&A.

The establishment of the 10% threshold provides the ability to assess the reasonableness of a relatively small percentage of yet to be audited costs in comparison to a much larger percentage of audited costs. The fact that some of those costs have been dealt with in prior applications does not diminish their value in terms of comparability to the subsequently incurred costs found in this application. The Board agrees with Board staff's position that the 10% threshold for unaudited costs in each application should apply to the total costs incurred to date in the smart meter deployment program at the time of the application.

Forecasted Costs and the Date of Disposition

PowerStream seeks final recovery of costs incurred in the installation of smart meters up to April 30, 2011. These costs include $500,000 of forecast one-time OM&A costs for anticipated repairs to customer-owned equipment for 225 meters not yet installed as of April 30, 2011. These one-time expenses were included for recovery in the Smart Meter Disposition Rate Rider ("SMDR") calculation but were for activities anticipated to take place after the date of disposition. PowerStream indicated that it had 3141 meter installations remaining for the 2011 calendar year.

Board staff submitted that PowerStream's application is inconsistent with Board policy in two ways: (i) capital and OM&A costs are not aligned with respect to date of disposition; and (ii) the claim that the application be treated as the final disposition of smart meter costs when PowerStream plans to add the remaining meters, yet to be installed, as capital additions in its next cost of service application. Board staff submitted that PowerStream should be consistent with the alignment of dates for all costs presented in the application. Board staff suggested that PowerStream elect to either:

a) Treat this application as a stand-alone smart meter cost recovery application to dispose of costs up to April 30, 2011. This would require the removal of all forecasted expenses for meters installed beyond April 30, 2011 from the SMDR and SMIRR calculations; or
b) Treat this application as the final disposition of costs. In this case, PowerStream would forecast the costs of installing the remaining meters through to December 31, 2011 for inclusion in the SMDR and update the SMIRR calculation to account for the ongoing revenue requirement of all meters (both forecasted and installed).

Board staff submitted that if PowerStream expected any material differences in the costs per meter or in the overall installation costs of the remaining smart meters, the company should seek to recover only costs for meters installed up to April 30, 2011.

VECC submitted that this application should be treated as a stand-alone smart meter cost recovery application, and not the final disposition of smart meter costs, because the level of unaudited costs is significant. VECC suggested that the Board only allow recovery of audited costs and that December 31, 2010 be used as the date of disposition.

PowerStream responded that April 30, 2011 should be used as the date of final disposition. PowerStream noted that as of April 30, 2011 it had installed over 100% of the required smart meters based on the mandated number of customers at the start of the smart meter implementation program. PowerStream noted that it adds approximately 5,000 to 6,000 new residential and GS < 50 kW customers per year and that, as a practical matter, it is necessary to establish a cut-off point where smart meter implementation is deemed complete and all further additions are part of the distributor's normal business activities.

As there is limited evidence on the record regarding the level of costs for repair work to customer owned property, Board staff submitted that PowerStream should continue to track the $500,000 in forecasted one-time repair costs in account 1556 for a future true up with rate payers, in the event that the Board approves the inclusion of these costs in the amounts to be disposed as part of this application. PowerStream agreed with Board staff's suggestion noting that it had primarily included the one-time expenses as part of the SMDR calculation due to concern over the availability of account 1556 as a means of tracking costs following final disposition.

Board Findings

The Board finds that April 30, 2011 is the appropriate date for the disposition of costs and directs that all forecasted costs associated with the installation of meters after that date be removed from the SMDR and SMIRR calculations. The Board agrees with PowerStream that, as a practical matter, a cut-off date must be selected for smart meter deployment, and the Board will consider this application to be PowerStream's final disposition of costs for smart meter deployment with the exception of the $500,000 in forecast repair and maintenance expenses which the Board expects will continue to be tracked in account 1556 and included in PowerStream's rebasing application expected in 2012 for 2013 rates. The Board provided its expectations with respect to the accounting of costs associated with this particular type of activity in its decision with reasons on the combined smart metering proceeding (EB-2007-0063).[4]

Cost Allocation Methodology

In PowerStream's prior application for smart meter cost recovery (EB-2010-0209), the Board made the following determination:

> The Board finds that a cost allocation approach based on class specific revenue requirement calculations offset by class specific smart meter funding to be inconsistent with previous Board decisions, and that there has been no clear requirement to track costs by class. The Board notes that historical funding collected from customer classes other than Residential and GS<50 kW is not material. The Board finds that a class specific calculation of the residual amounts for disposition of smart meter costs for each rate class is unwarranted, as there is insufficient benefit given the additional complexity.
>
> The Board also finds the cost allocation approach submitted by Board staff and accepted by PowerStream to be reasonable. In making this finding the Board is mindful that full cost causality should be the guiding principle. However, the Board accepts the argument advanced by PowerStream in its reply submission that VECC's proposal for full cost causality would result in significant directional swings for customers in the future. This volatility should be generally avoided.

In the current application, PowerStream allocated the revenue requirement as follows:

- Return (deemed interest plus return on equity) and Amortization have been allocated between the customer classes based on the capital costs of the meters installed for each class.
- OM&A has been allocated based on the number of meters installed for each class.

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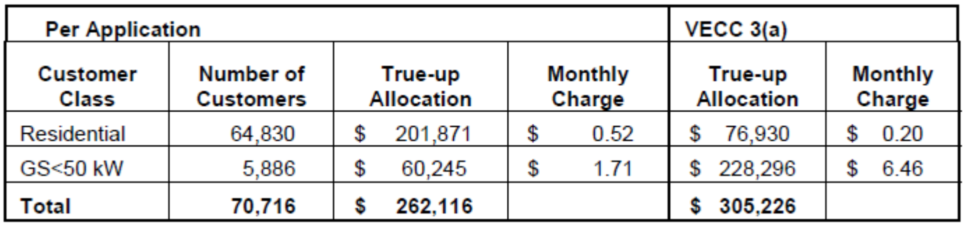
[4] Decision with Reasons (EB-2007-0063), Replacement and Repair Costs, page 17, August 8, 2007.

- PILs have been allocated based on the revenue requirement allocated to each class before PILs.

Board staff submitted that PowerStream had correctly applied the cost allocation methodology approved by the Board in EB-2010-0209 and that a change in cost allocation methodology was not warranted at this time.

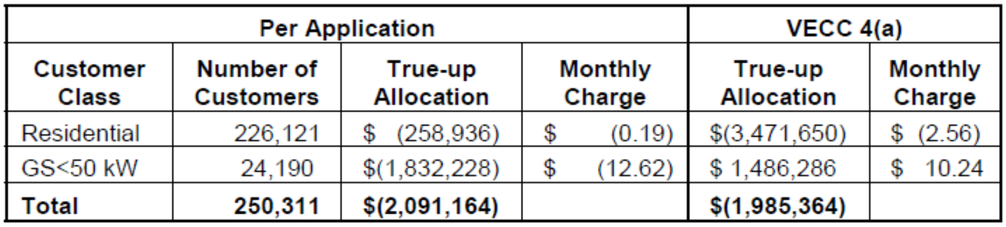
As part of their IRs, VECC requested PowerStream to complete a separate smart meter revenue requirement model for the residential and GS < 50 kW customer classes in each rate zone and to recalculate the SMDR, SMIRR and bill impacts using the class specific revenue requirements.[5] Table 5 and Table 6, below, compare the recalculated SMDRs for the North and South rate zone, respectively, to the original calculations provided by PowerStream in the application. A summary of the updated bill impact calculations is reproduced in Table 7. The net result is a shift in costs from the residential to the GS<50 kW customer class.

Table 5 - True-up Allocation and SMDR Calculation (North rate zone)[6]



Per Application				VECC 3(a)	
Customer Class	Number of Customers	True-up Allocation	Monthly Charge	True-up Allocation	Monthly Charge
Residential	64,830	$ 201,871	$ 0.52	$ 76,930	$ 0.20
GS<50 kW	5,886	$ 60,245	$ 1.71	$ 228,296	$ 6.46
Total	**70,716**	**$ 262,116**		**$ 305,226**	

Table 6 - True-up Allocation and SMDR Calculation (South rate zone)[7]



Per Application				VECC 4(a)	
Customer Class	Number of Customers	True-up Allocation	Monthly Charge	True-up Allocation	Monthly Charge
Residential	226,121	$ (258,936)	$ (0.19)	$(3,471,650)	$ (2.56)
GS<50 kW	24,190	$(1,832,228)	$ (12.62)	$ 1,486,286	$ 10.24
Total	**250,311**	**$(2,091,164)**		**$(1,985,364)**	

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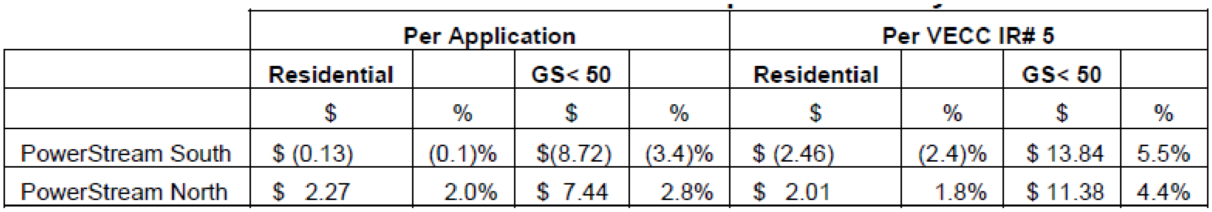
[5] Responses to VECC IRs (EB-2011-0128), IRs 3, 4 and 5, September 9, 2011.

[6] Ibid, Table VECC 3-2, page 7.

[7] Ibid, Table VECC 4-2, page 9.

Table 7 - Bill Impact Summary of Proposed Cost Allocation Methodologies for each rate zone[8]



	Per Application				Per VECC IR# 5			
	Residential		GS< 50		Residential		GS< 50	
	$	%	$	%	$	%	$	%
PowerStream South	$ (0.13)	(0.1)%	$(8.72)	(3.4)%	$ (2.46)	(2.4)%	$ 13.84	5.5%
PowerStream North	$ 2.27	2.0%	$ 7.44	2.8%	$ 2.01	1.8%	$ 11.38	4.4%

VECC submitted that the differences between the two cost allocation methodologies were significant and that full cost causality should be the guiding principle. VECC submitted that smart meter cost recovery should be done by a class specific rate rider to reflect the costs for each customer class. VECC also submitted that a separate model should be completed for the GS > 50 kW customer class and that any funds collected from customers of that class be returned, with carrying charges, to those customers. Board staff submitted that the calculations shown in PowerStream's responses to VECC IRs 3, 4 and 5 mirror the methodology that the Board determined was unwarranted in the EB-2010-0209 proceeding.

PowerStream did not submit any objections to the methodology proposed by VECC. PowerStream submitted that, should the Board approve VECC's approach, it would require direction from the Board regarding the treatment of smart meter funding adder amounts collected from the GS > 50 kW and Large Use customer classes.

Board Findings

In PowerStream's prior application the Board did not approve VECC's cost allocation approach, in part because the differences between the two approaches were not significant enough to warrant the additional complexity. This is not the case in this application as the differences here are significant. The Board finds that PowerStream should adopt the cost allocation methodology proposed by VECC. The Board notes that VECC's proposal may not be appropriate or feasible for all distributors as the necessary data may not be readily available. Since PowerStream has the necessary data, has provided the calculation and did not object to this approach, the Board concludes a change in cost allocation methodology is appropriate for this application.

The Board directs PowerStream to allocate the smart meter adder amounts collected from the GS > 50 kW and Large Use customer classes evenly to the residential and GS

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[8] Ibid, Table VECC 5-5, page 11.

< 50 kW classes when calculating the true-up for the SMDR. The Board concludes this approach is appropriate because the amounts involved are not significant enough to warrant a more precise allocation. To be clear, PowerStream should reduce the class specific revenue requirements for each subject class by the amount of the class-specific revenues that have been collected through the adder, plus the additional revenues allocated to each of the subject classes from the non-participating classes.

Carrying Charges on OM&A and Amortization

The Board notes that PowerStream has not requested recovery of carrying charges on OM&A and amortization expense for its historical costs. Given that carrying charges have been applied by PowerStream to the revenues collected from customers, it is open to the company to include these carrying charges for recovery when filing its draft Rate Order following the issuance of this Decision. The Board is of the view that the application of carrying charges should be symmetrical. The Board also notes that an FAQ for the Board’s Accounting Procedures Handbook, issued in August 2008, contemplated the application of carrying charges on OM&A and Amortization expense.

It is the Board’s expectation that Board staff (and VECC if it so wishes), will review and confirm the calculations supporting the revised residual class-specific revenue requirements and provide any comments they may have with respect to the application of carrying charges in the event that PowerStream includes such charges for recovery in its draft Rate Order.

IMPLEMENTATION

The Board expects PowerStream to file detailed supporting material, including all relevant calculations showing the impact of this Decision on PowerStream’s class-specific smart meter revenue requirements and the determination of the updated SMDR and SMIRR.

PowerStream requested an implementation date of November 1, 2011 for its new rates. Given the filing date and the time required to process an application of this nature, the Board has determined that an implementation date of December 1, 2011 is appropriate. In developing its draft Rate Order, PowerStream is directed to establish the SMDR based on a five month recovery period to April 30, 2012 and to accommodate within the SMDR the applicable revenue requirement amounts related to the month of November.

The SMIRR shall be effective and implemented on December 1, 2011. The Board notes that this rider is based on an annual revenue requirement and will be in effect until the effective date of PowerStream's next cost of service rate order.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the Ontario Energy Board Act, 1998. The Board will determine eligibility for costs in accordance with its *Practice Direction on Cost Awards*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

All filings to the Board must quote the file number, EB-2011-0128, 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/OEB/Industry. If the web portal is not available, parties may email their documents 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.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS:
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary
Tel: 1-877-632-2727 (toll free)
Fax: 416-440-7656
E-mail: Boardsec@ontarioenergyboard.ca

THE BOARD ORDERS THAT:

1. PowerStream shall file with the Board, and shall also forward to VECC, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order, within 7 days of the date of this Decision and Order. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. VECC and Board staff shall file any comments on the draft Rate Order with the Board and forward to PowerStream within 5 days of the date of filing of the draft Rate Order.

3. PowerStream shall file with the Board and forward to VECC responses to any comments on its draft Rate Order within 5 days of the date of receipt of the submission.

4. VECC shall file with the Board and forward to PowerStream its cost claim within 21 days from the date of this Decision and Order.

5. PowerStream shall file with the Board and forward to VECC any objections to the claimed costs within 35 days from the date of this Decision and Order.

6. VECC shall file with the Board and forward to PowerStream any responses to any objections for cost claims within 42 days of the date of this Decision and Order.

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

DATED at Toronto, November 21, 2011

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy
Board

Commission de l'énergie
de l'Ontario

EB-2010-0110
EB-2010-0365

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 PowerStream Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2011.

BEFORE: Karen Taylor
Presiding Member

Paul Sommerville
Member

DECISION AND ORDER

Introduction

PowerStream Inc. ("PowerStream"), is a licensed distributor of electricity providing service to customers within two service territories – Barrie ("PowerStream – Barrie") and South ("PowerStream – South"). PowerStream filed an application with the Ontario Energy Board (the "Board") received on October 15, 2010, 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 PowerStream charges for electricity distribution, to be effective May 1, 2011.

On December 15, 2008, the Board made an oral decision (EB-2008-0335) which granted PowerStream and Barrie Hydro Distribution Inc. ("Barrie Hydro") leave to amalgamate. On March 16, 2010, the Board found (EB-2010-0025) it to be in the public interest to grant PowerStream's requested licence amendment to include the service area of Barrie Hydro and to cancel the distribution licence of Barrie Hydro.

The application for PowerStream – South's service territory was given Board File No. EB-2010-0110. The application for the PowerStream – Barrie's service territory was given Board File No. EB-2010-0365. As the applications contain common elements and adjustments under the 3rd Generation Incentive Rate Mechanism ("IRM"), the Board has combined its findings in this Decision and Order where applicable. In situations where differentiations need to be made between PowerStream – Barrie and PowerStream – South, they are separately addressed in this Decision and Order.

PowerStream is one of 80 electricity distributors in Ontario regulated by the Board. In 2008, the Board announced the establishment of a new multi-year electricity distribution rate-setting plan, the 3rd Generation IRM process, which would be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review. As part of the plan, PowerStream is one of the electricity distributors that will have its rates adjusted for 2011 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 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on July 14, 2008, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008, and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (together the "Reports"). Among other things, the Reports contained the relevant guidelines for 2011 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On July 9, 2010 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 PowerStream's rate application was given through newspaper publication in PowerStream's service areas advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. The Board received three letters of comment opposing

PowerStream's proposed rate increases. The Vulnerable Energy Consumers Coalition ("VECC") applied for and was granted intervenor status in this proceeding. VECC was also granted cost eligibility for participation in the proceeding in relation to PowerStream's request for lost revenue adjustment mechanism ("LRAM") and shared savings mechanism ("SSM") 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;
- Changes in the Federal and Provincial Income Tax Rates;
- Smart Meter Funding Adder;
- Revenue-to-Cost Ratios (PowerStream – Barrie);
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Accounts;
- Review and Disposition of Lost Revenue Adjustment Mechanism and Shared Savings Mechanism; and
- Late Payment Penalty Litigation Costs.

Price Cap Index Adjustment

PowerStream's rate application was filed on the basis of the Filing Requirements. In fixing new distribution rates and charges for PowerStream, the Board has applied the policies described in the Filing Requirements and the Reports.

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 PowerStream's utility specific stretch factor of 0.4%. Based on the final 2010 data published by Statistics Canada, the Board has established the price escalator to be 1.3%. The resulting price cap index adjustment is therefore 0.18%. The rate models reflect this price cap index adjustment. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.

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 Charge; and
- Retail Service Charges.

Changes in the Federal and Provincial Income Tax Rates

In its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* dated September 17, 2008, the Board determined that a 50/50 sharing of the impact of currently known legislated changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate for the 3rd Generation IRM applications. This was based on a decision of the Board in a proceeding in relation to natural gas distributors' (EB-2007-0606/615) incentive regulation applications in which tax as a Z-factor was being considered. In that decision, the Board found that a 50/50 sharing is appropriate because it recognizes that tax changes already flow to some extent through the inflation factor, though the precise timing and quantum of the tax reduction during a current IRM period is not known.

The calculated annual tax reduction over the 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 derived using annualized consumption by customer class underlying the Board-approved base rates.

In 2011, the maximum income tax rate is 28.25%, the minimum rate for those distributors eligible for both the federal and Ontario small business deduction is 15.50%, and the blended tax rate varies for certain distributors that are only eligible for the Ontario small business deduction. The model provided to distributors calculates the amount of change caused by the tax rate reductions and adjusts distribution rates by

50% of the total change from those taxes included in the most recent cost of service base distribution rates.

The Board finds that a 50/50 sharing of the impact of changes from the tax level reflected in the Board-approved base rates to the currently known legislated tax level for 2011 for PowerStream is appropriate and shall be effected by means of a rate rider over a one-year period.

Smart Meter Funding Adder

On October 22, 2008 the Board issued the *Guideline for Smart Meter Funding and Cost Recovery* which sets out the Board's filing requirements in relation to the funding and recovery of costs associated with smart meter activities conducted by electricity distributors.

PowerStream - South filed an application in 2010 (EB-2010-0209) for the recovery of smart meter costs installed in 2008 and 2009. As part of that application, Power Stream – South received approval from the Board to discontinue its smart meter funding adder ("SMFA") of $1.81 per metered customer per month effective December 31, 2010, given the advanced stage of PowerStream – South's smart meter program.

PowerStream – Barrie requested in this application to discontinue its current SMFA of $1.61 per metered customer per month since the smart meter installation program is expected to be completed by the end of 2010.

The Board notes that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board (G-2008-0002). Since the deployment of smart meters on a province-wide basis is now nearing completion, the Board expects distributors to file for a final prudence review at the earliest possible opportunity following the availability of audited costs. For those distributors that are scheduled to file a cost-of-service application for 2012 distribution rates, the Board expects that they will apply for the disposition of smart meter costs and subsequent inclusion in rate base. For those distributors that are scheduled to remain on IRM, the Board expects these distributors to file an application with the Board seeking final approval for smart meter related costs. Since PowerStream – Barrie is in an advanced stage with its smart meter deployment program, the Board will approve PowerStream – Barrie's proposal to discontinue its SMFA of $1.61 effective May 1, 2011.

PowerStream's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall be continued.

Revenue-to-Cost Ratios (PowerStream – Barrie)

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.

The Board's Decision (EB-2007-0746) for PowerStream – Barrie's 2008 cost of service rate application prescribed a phase-in period to adjust its revenue-to-cost ratios.

PowerStream – Barrie proposed to adjust its revenue-to-cost ratios in the current application as shown in Column 2 of Table 1.

Table 1 – PowerStream – Barrie's Revenue-to-Cost Ratios (%)

Rate Class	**2010 Ratio** Column 1	**Proposed 2011 Ratio** Column 2	**Target Range** Column 3
Residential	113.0	111.9	85 – 115
GS < 50 kW	100.0	100.0	80 – 120
GS 50 – 4,999 kW	81.0	81.0	80 – 180
Large Use	86.0	86.0	85 – 115
Street Lighting	55.0	70.0	70 – 120
USL	99.0	99.0	80 – 120

VECC submitted that the revised revenue-to-cost ratios are in accordance with the Board's decision in EB-2008-0160. In that decision, the Board directed Board staff to adjust the rate model to enable distributors to reflect how the low voltage charges and transformer ownership allowance were allocated for the purpose of calculating the revenue-to-cost ratios in PowerStream – Barrie's 2008 cost of service proceeding (EB-2007-0746)

Board staff submitted that the revised revenue-to-cost ratios are in accordance with the Board's findings in its EB-2007-0746 decision.

The Board agrees that the revised revenue-to-cost ratios are in accordance with the Board's findings referenced above. The Board therefore approves the revised revenue-to-cost ratios.

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 July 8, 2010 the Board issued revision 2.0 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 2011. 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 distributor's specific RTSRs, Board staff provided a filing module. On January 18, 2011, the Board issued its Rate Order for Hydro One Transmission (EB-2010-0002) which adjusted the UTRs effective January 1, 2011. The new UTRs are shown in the following table:

Table 2 – Uniform Transmission Rates	**kW Monthly Rates**		**Change**
	Jan 1, 2010	**Jan 1, 2011**	
Network Service Rate	$2.97	$3.22	+8.4%
<u>Connection Service Rates</u>			
Line Connection Service Rate	$0.73	$0.79	
Transformation Connection Service Rate	$1.71	$1.77	
			+4.9%

The Board has adjusted each distributor's rate application model to incorporate these changes.

Based on the filing module provided by Board staff and the new UTRs effective January 1, 2011 noted in the above table, the Board approves the changes to the RTSRs calculated in the filing module for each of the South and Barrie service areas

Review and Disposition of Group 1 Deferral and Variance Accounts

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (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.

PowerStream – Barrie and PowerStream – South's Group 1 account balances did not exceed the preset disposition threshold referenced above. The Board therefore finds that no disposition is required at this time.

Review and Disposition of Lost Revenue Adjustment Mechanism and Shared Savings 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 and SSM.

The Board's Decision on LRAM in the Horizon Utilities Corporation's ("Horizon") application (EB-2009-0192) stated that distributors are to use the most current input assumptions which have been adopted by the Board when preparing their LRAM applications as these assumptions represent the best estimate of the impacts of the programs.

(i) PowerStream – Barrie

PowerStream – Barrie sought approval to recover an LRAM and SSM claim totaling $216,816 ($209,821 for LRAM and $6,995 for SSM) over a one-year period.

In its submission, VECC argued that the LRAM and SSM claims were prepared using appropriate input assumptions and should be accepted by the Board.

Board staff submitted that PowerStream – Barrie's application for LRAM recovery is consistent with the CDM Guidelines and the Board's Decision on Horizon's application (EB-2009-0192) for the LRAM recovery. With respect to the SSM amount, Board staff noted that in response to Board staff's interrogatory #5, PowerStream – Barrie indicated that the use of the most recent OPA Input Assumption list resulted in a lower SSM amount. Board staff submitted that this approach, although inconsistent with the CDM Guidelines is acceptable.

The Board continues to endorse the principle of LRAM, which is that distributors are to be kept whole for revenue that they have foregone as a direct consequence of implementing CDM programs. The Board is of the view that the most current OPA Measures and Assumptions List, as updated by the OPA from time to time, represents the best estimate of losses associated with a distributor's CDM programs.

The Board approves the recovery of an LRAM amount of $209,821 for PowerStream – Barrie which is consistent with the principles set out in the Horizon Decision. The LRAM amount shall be recovered by means of a volumetric rate rider over a one-year period.

The Board will also approve the recovery of an SSM amount of $6,995. The SSM amount shall be recovered by means of a volumetric rate rider over a one-year period.

(ii) PowerStream – South

PowerStream – South sought approval to recover an LRAM and SSM claim totaling $522,932 ($519,799 for LRAM and $6,133 for SSM) over a one-year period.

In its submission, VECC argued that the LRAM and SSM claims were prepared using appropriate input assumptions and should be accepted by the Board. Board staff also submitted that PowerStream – South's application for LRAM and SSM recovery is consistent with the CDM Guidelines and the Board's Decision on Horizon's application (EB-2009-0192) for LRAM recovery. Board staff supported the recovery of the LRAM and SSM amounts proposed by PowerStream – South.

The Board continues to endorse the principle of LRAM, which is that distributors are to be kept whole for revenue that they have foregone as a direct consequence of implementing CDM programs. The Board is of the view that the most current OPA Measures and Assumptions List, as updated by the OPA from time to time, represents the best estimate of losses associated with a distributor's CDM programs.

The Board approves the recovery of an LRAM amount of $519,799 for PowerStream – South which is consistent with the principles set out in the Horizon Utilities Corporation Decision. The LRAM amount shall be recovered by means of a volumetric rate rider over a one-year period.

The Board also approves the recovery of an SSM amount of $6,133. The SSM amount shall be recovered by means of a volumetric rate rider over a one-year period.

Late Payment Penalty Litigation Costs

In this application, PowerStream requested the recovery of a one time expense of $1,019,322 related to the late payment penalty ("LPP") costs and damages resulting from a court settlement that addressed litigation against many of the former municipal electricity utilities in Ontario.

On October 29, 2010 the Board commenced a generic proceeding on its own motion to determine whether Affected Electricity Distributors[1], including PowerStream, should be allowed to recover from their ratepayers the costs and damages incurred as a result of the Minutes of Settlement approved on April 21, 2010 by the Honourable Mr. Justice Cumming of the Ontario Superior Court of Justice (Court File No. 94-CQ-r0878) and as amended by addenda dated July 7, 2010 and July 8, 2010 in the late payment penalty class action and if so, the form and timing of such recovery. This proceeding was assigned file No. EB-2010-0295.

On February 22, 2011, the Board issued its Decision and Order and determined that it is appropriate for the Affected Electricity Distributors to be eligible to recover the costs and damages associated with the LPP class action in rates. The decision set out a listing of each Affected Electricity Distributor and their share of the class action costs that is approved for recovery. The Board also directed Affected Electricity Distributors such as PowerStream to file with the Board detailed calculations including supporting

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[1] As defined in the Board's Decision and Order EB-2010-0295

documentation, outlining the derivation of the rate riders based on the methodology outlined in the EB-2010-0295 Decision and Order. The Board noted that the rate riders submitted would be verified in each Affected Electricity Distributor's IRM or cost of service application, as applicable. PowerStream elected to recover the amount approved in the EB-2010-0295 proceeding and accordingly filed the associated rate riders.

In deriving the proposed rate riders, PowerStream noted that it does not separate distribution revenues by service area (i.e. Barrie vs. South). Therefore, the allocation was done on an overall basis.

The Board has reviewed PowerStream's proposed rate riders for both the South and Barrie service areas and approves them as filed.

Rate Model

With this Decision, the Board is providing PowerStream with rate models (spreadsheet) and applicable supporting models for PowerStream – Barrie and PowerStream – South and a combined 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 for each of PowerStream – Barrie and PowerStream – South to ensure that they were in accordance with the 2010 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. PowerStream's new distribution rates for each service territory served by PowerStream – Barrie and PowerStream – South shall be effective May 1, 2011.

2. PowerStream shall review the draft Tariff of Rates and Charges set out in Appendix A for PowerStream – Barrie and PowerStream – South. PowerStream 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 seven (7) calendar days of the date of this Decision and Order.

3. If the Board does not receive a submission from PowerStream 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, 2011, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2011. PowerStream 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 PowerStream 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 PowerStream and will issue a final Tariff of Rates and Charges.
5. PowerStream shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

Cost Awards

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

1. Intervenors eligible for cost awards shall submit their cost claims by no later than 14 days from the date of this Decision and Order.
2. PowerStream shall file its response, if any, by no later than 28 days from the date of this Decision and Order.
3. Intervenors shall file their reply to PowerStream's response by no later than 35 days from the date of this Decision and Order.

All filings to the Board must quote file number **EB-2010-0110/EB-2010-0365,** 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 7 paper copies.

DATED at Toronto, April 7, 2011

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-2010-0110/EB-2010-0365

DATED: April 7, 2011

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.89
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.16
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.28
Distribution Volumetric Rate	$/kWh	0.0134
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	28.39
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.43
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.01
Distribution Volumetric Rate	$/kWh	0.0115
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0002)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

GENERAL SERVICE 50 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, 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	83.71
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	5.38
Distribution Volumetric Rate	$/kW	3.4730
Low Voltage Service Rate	$/kW	0.0472
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0417)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kW	0.0001
Retail Transmission Rate – Network Service Rate	$/kW	2.3510
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9299

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	2,154.67
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	138.96
Distribution Volumetric Rate	$/kW	1.0393
Low Voltage Service Rate	$/kW	0.0558
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0146)
Retail Transmission Rate – Network Service Rate	$/kW	2.7582
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0990

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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EB-2010-0110
EB-2010-0365

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is 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 customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.20
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.09
Distribution Volumetric Rate	$/kWh	0.0086
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0006)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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EB-2010-0110
EB-2010-0365

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.98
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.06
Distribution Volumetric Rate	$/kW	9.3098
Low Voltage Service Rate	$/kW	0.0401
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.1216)
Retail Transmission Rate – Network Service Rate	$/kW	1.7966
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7885

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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EB-2010-0110
EB-2010-0365

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 operation, 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.83
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.01
Distribution Volumetric Rate	$/kW	4.8192
Low Voltage Service Rate	$/kW	0.0367
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.1065)
Retail Transmission Rate – Network Service Rate	$/kW	1.7786
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7230

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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EB-2010-0110
EB-2010-0365

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	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
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
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary Service install and remove – overhead – no transformer	$	500.00

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.21
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.16
Distribution Volumetric Rate	$/kWh	0.0136
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0005)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.97
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.43
Distribution Volumetric Rate	$/kWh	0.0163
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery (2011) – effective until April 30, 2012	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE 50 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 expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	393.23
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	5.38
Distribution Volumetric Rate	$/kW	1.8233
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0504)
Retail Transmission Rate – Network Service Rate	$/kW	2.3432
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9363

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE 50 to 4,999 kW TOU SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW and who has an electrical service of at least 600 amps at 600/347 volts or 1600 amps at 208/120 volts. If the customer meets these criteria then an interval meter is required. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	393.23
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	5.38
Distribution Volumetric Rate	$/kW	1.8233
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0504)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.1107
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5704

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than or is expected to be equal to or greater than 5000 kW. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	9,605.71
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	138.96
Distribution Volumetric Rate	$/kW	0.5866
Low Voltage Service Rate	$/kW	0.3886
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.0592)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.1192
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5775

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Former Barrie Hydro Distribution Inc. Service Area

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW. As determined by Barrie Hydro Distribution Inc. because of the type of connection or location a meter is not feasible in these situations. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	7.88
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.09
Distribution Volumetric Rate	$/kWh	0.0160
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – effective until April 30, 2012	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	2.6620

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.99
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.01
Distribution Volumetric Rate	$/kW	11.1976
Low Voltage Service Rate	$/kW	0.2301
Rate Rider for Tax Change – effective until April 30, 2012	$/kW	(0.3213)
Retail Transmission Rate – Network Service Rate	$/kW	1.8511
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5295

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. 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 utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – no disconnection	$	15.00
Disconnect/Reconnect at Meter - during Regular Hours	$	30.00
Disconnect/Reconnect at Meter - after Regular Hours	$	185.00
Disconnect/Reconnect at Pole - during Regular Hours	$	185.00
Disconnect/Reconnect at Pole - after Regular Hours	$	415.00
Service Call – customer owned equipment – charge based on time and materials		
Service Call – after regular hours – charge based on time and materials		
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2011

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

EB-2010-0110
EB-2010-0365

Former Barrie Hydro Distribution Inc. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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	1.0565
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0462
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0209

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 PowerStream Inc. for an order or orders approving or fixing a just and reasonable distribution rates related to Smart Meter deployment, to be effective November 1, 2010.

BEFORE: Ken Quesnelle
Presiding Member

Cynthia Chaplin
Chair and Member

RATE ORDER
(Corrected)

PowerStream Inc. ("PowerStream") filed an application with the Ontario Energy Board ("the Board") dated June 11, 2010 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B for distribution rates and requesting approval of certain smart meter expenditures and a change to its utility-specific smart meter funding adder.

PowerStream continues to operate two separate rate zones, PowerStream South, the legacy service area and PowerStream North, the Barrie service area. This application pertains to the legacy service area only. The Board assigned the application file number EB-2010-0209.

On June 28, 2010, the Board issued a Notice of Application and Written Hearing (the "Application"). The Vulnerable Energy Consumers Coalition ("VECC") was approved as an intervenor.

The Board's Decision and Order regarding the Application was issued on November 22, 2010. The Board ordered PowerStream to file a draft rate order reflecting the Board's findings and indicated that it expected PowerStream to file customer rate impacts and detailed supporting information showing the calculation of the final rate riders.

PowerStream filed a draft rate order on November 25, 2010. The intervenor in this proceeding had the opportunity to file comments within 5 days from the date of the filing of the draft rate order. No comments were received.

The Board has reviewed the information provided and the proposed Tariff of Rates and Charges and is satisfied that the document accurately reflects the Board's Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective January 1, 2011, for electricity consumed or estimated to have been consumed on and after January 1, 2011.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous Tariff of Rates and Charges approved by the Ontario Energy Board for PowerStream Inc.'s service area, and is final in all respects.

3. PowerStream Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, December 10, 2010.
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A
TO THE
RATE ORDER
FOR
POWERSTREAM INC.
EB-2010-0209
DATED: DECEMBER 10, 2010
(corrected)

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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

EB-2010-0209

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.87
Rate Rider for Smart Meter Disposition – effective until April 30, 2011	$	1.89
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.28
Distribution Volumetric Rate	$/kWh	0.0134
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	(0.0023)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

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

EB-2010-0209

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	28.34
Rate Rider for Smart Meter Disposition – effective until April 30, 2011	$	1.49
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.01
Distribution Volumetric Rate	$/kWh	0.0115
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0001)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	(0.0024)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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

EB-2010-0209

GENERAL SERVICE 50 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, 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.

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	$	83.56
Distribution Volumetric Rate	$/kW	3.4668
Low Voltage Service Rate	$/kW	0.0472
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0233)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(0.9971)
Retail Transmission Rate – Network Service Rate	$/kW	2.1613
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9107

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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EB-2010-0209

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	2,150.80
Distribution Volumetric Rate	$/kW	1.0374
Low Voltage Service Rate	$/kW	0.0558
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0082)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(1.7100)
Retail Transmission Rate – Network Service Rate	$/kW	2.5356
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0763

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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EB-2010-0209

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is 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 customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.17
Distribution Volumetric Rate	$/kWh	0.0086
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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

EB-2010-0209

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to 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)	$	1.98
Distribution Volumetric Rate	$/kW	9.2931
Low Voltage Service Rate	$/kW	0.0401
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0679)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(2.8005)
Retail Transmission Rate – Network Service Rate	$/kW	1.6516
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7722

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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EB-2010-0209

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 operation, 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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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.83
Distribution Volumetric Rate	$/kW	4.8105
Low Voltage Service Rate	$/kW	0.0367
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0595)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(0.8317)
Retail Transmission Rate – Network Service Rate	$/kW	1.6351
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7081

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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EB-2010-0209

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

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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EB-2010-0209

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		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	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
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
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary Service install and remove – overhead – no transformer	$	500.00

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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

EB-2010-0209

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

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

Ontario

EB-2009-0246

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 PowerStream Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2010.

BEFORE: Paul Vlahos
Presiding Member

DECISION AND ORDER

Introduction

PowerStream Inc. ("PowerStream"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2010.

PowerStream is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2008, the Board announced the establishment of a new multi-year electricity distribution rate-setting plan, the 3rd Generation Incentive Rate Mechanism ("IRM") process, that will be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review. As part of the plan, PowerStream is one of the electricity distributors that will have its rates adjusted for 2010 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 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on July 14, 2008, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008, and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (together the "Reports"). Among other things, the Reports contained the relevant guidelines for 2010 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process. On July 22, 2009 the Board issued an update to Chapter 3 of the Board's "Filing Requirements for Transmission and Distribution Applications" (the "Filing Requirements"), which outlined the filing requirements for IRM applications by electricity distributors.

Notice of PowerStream's rate application was given through newspaper publication in PowerStream'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. There were no intervention requests and no comments were received. Board staff participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, 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;
- Changes in the Federal and Provincial Income Tax Rates;
- Harmonized Sales Tax;
- Smart Meter Funding Adder;
- Adjustment to the Large Use Rate Class;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Accounts; and
- Introduction of MicroFIT Generator Service Classification and Rate.

Price Cap Index Adjustment

PowerStream's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for PowerStream, the Board has applied the policies described in the Reports.

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 PowerStream's utility specific stretch factor of 0.4%. Based on the final 2009 data published by Statistics Canada, the Board has established the price escalator to be 1.3%. The resulting price cap index adjustment is therefore 0.18%. The Board has adjusted the rate model to reflect the newly calculated price cap index adjustment. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.

The price cap index adjustment will not apply to the following components of distribution 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; and
- Retail Service Charges.

Changes in the Federal and Provincial Income Tax Rates

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic Outlook and Fiscal Review (the "Fiscal Review"). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

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[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15 million effective January 1, 2008.

The Federal Budget which was presented on January 27, 2009 and received Royal Assent on March 12, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009.

On March 26, 2009, the Ontario provincial budget was presented and Bill 218, the enabling legislation, received Royal Assent on December 15, 2009. For corporations, the basic income tax rates will decrease in stages from 14% to 10% by July 1, 2013, while on July 1, 2010, the small business rate will drop from 5.5% to 4.5%, after the small business deduction is made where applicable. A provincial small business surtax claws back the benefit of the small business deduction when taxable income of associated corporations exceeds $500,000 and eliminates the benefit completely once taxable income, on an associated basis, reaches $1,500,000. The surtax will be eliminated on July 1, 2010.

The following table summarizes past, current and impending tax changes.

Tax Rates **Federal & Provincial** **As of December 15, 2009**	**Effective January 1, 2009**	**Effective January 1, 2010**	**Effective January 1, 2011**	**Effective January 1, 2012**	**Effective January 1, 2013**	**Effective January 1, 2014**
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Surtax (4% of line 3)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-9.00%	-10.00%	-11.50%	-13.00%	-13.00%	-13.00%
	19.00%	18.00%	16.50%	15.00%	15.00%	15.00%
Ontario income tax	14.00%	13.00%	11.75%	11.25%	10.50%	10.00%
Combined federal and Ontario	**33.00%**	**31.00%**	**28.25%**	**26.25%**	**25.50%**	**25.00%**
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	5.50%	5.00%	4.50%	4.50%	4.50%	4.50%
Ontario surtax claw-back of 4.25% (eliminated July 1, 2010) starts at $500,000 and eliminates the SBC at $1,500,000.						
Ontario surtax	4.25%	2.125%	0.00%	0.00%	0.00%	0.00%
Ontario Capital Tax						
Capital deduction	15,000,000	15,000,000	0	0	0	0
Capital tax rate	0.225%	0.075%	0.0%	0.0%	0.0%	0.0%
OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.						

The Board is of the view that these tax changes when combined could be material and should be reflected in rates using a 50/50 sharing as determined by the Board in the Reports. Therefore the incentive regulation rate model shall be adjusted accordingly.

Harmonized Sales Tax

The 8% Ontario provincial sales tax (“PST”) and the 5% Federal goods and services tax (“GST”) will be harmonized effective July 1, 2010, at 13%, pursuant to Ontario Bill 218 which received Royal Assent on December 15, 2009.

The PST is currently included in a distributor’s OM&A expenses and capital expenditures. The PST is therefore included in the distributor’s revenue requirement and is recovered from ratepayers through distribution rates.

When the PST and GST are harmonized, distributors will pay the HST on purchased goods and services but will claim an input tax credit (“ITC”) for the PST portion. Therefore, the distributor will no longer incur that portion of the tax that was formerly applied as PST.

Board staff submitted that the Board may wish to consider the establishment of a deferral account to record the amounts, after July 1, 2010 and until PowerStream’s next cost-of-service rebasing application, that were formerly incorporated as the 8% PST on capital expenditures and expenses incurred, but which will now be eligible for an ITC. This account would track the incremental change due to the introduction of the HST that incorporates an increased ITC from the current 5% to a 13% level.

PowerStream pointed out a number of concerns with respect to establishing a deferral account related to the harmonized sales tax (HST), including transitional issues, uncertainty about increased costs and increased demands on cash flow. PowerStream further submitted that the Board should consider addressing this issue in a generic context since this is an industry-wide issue.

The Board finds that it would not be incrementally onerous for distributors to track the ITC amounts as the distributor will need to file ITC information in GST/HST returns and go through the quantification process to satisfy the requirements by the tax authorities and that the final amounts will be confirmed by the tax authorities. In regulatory parlance, what Staff is suggesting is in the nature of a deferral account, not a variance account, and as such there is no need to compare these amounts with any reference to PST levels reflected in existing rates.

Rather, the issue in the Board's view is whether a distributor's cost reductions arising from the implementation of the HST should be returned to the ratepayers. In that regard, the Board notes that to do so would be consistent with what the Board has done with tax changes in second and third generation IRMs. In second generation IRM, the Board treated 100% of the tax changes as a Z factor. In the third generation IRM, the Board determined that tax changes would be shared equally between ratepayers and the shareholder. The 50% was considered appropriate as the changes in input prices will flow through the GDP-IPI over time to some degree. The same rationale applies in the case of the HST.

The Board therefore directs that, beginning July 1, 2010, PowerStream shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)), the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and which become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of PowerStream's next cost of service rate order. Fifty percent (50%) of the confirmed balances in the account shall be returnable to the ratepayers.

The Board may issue more detailed accounting guidance in the future. In that event, the Applicant should make the appropriate accounting entries, if and as applicable.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law. PowerStream is authorized to conduct smart meter activities because it is identified in paragraph 3 of section 1(1) of O. Reg. 427/06.

PowerStream requested to change its utility-specific smart meter funding adder from $1.04 to $1.81 per metered customer per month. The Board approves the funding adder proposed by PowerStream as reasonable. This new funding adder will be reflected in the Tariff of Rates and Charges. PowerStream's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.81 per metered customer per month is intended to provide funding for PowerStream's smart metering activities in the 2010 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that PowerStream applies for the recovery of these costs.

Adjustment to the Large Use Rate Class

PowerStream proposed to re-classify two customers from the General Service 50 to 4,999 kW ("GS>50 kW") class to the Large Use class.

At the time of preparing its 2009 Cost of Service rate filing, PowerStream updated its Cost Allocation Study to reflect the fact that the Large Use class consisted of a single customer using a short dedicated connection to a transformer station. This resulted in a revenue-to-cost ratio that exceeded the upper limit of the Board-approved range. The adjustment approved by the Board to bring this to the approved range resulted in a significant rate reduction for the Large Use rate class. PowerStream indicated that the revised rates may not be appropriate for any new Large Use customers and, accordingly, no customers would be moved from the GS>50 kW class to the Large Use class without making adjustments to the Large Use rates to better reflect the cost of serving any new customers.

Based on a recent review of customer consumption levels, PowerStream identified two customers that have an average demand in excess of 5,000 kW and therefore should be re-classified to the Large Use class. PowerStream indicated that these two customers utilize most components of its distribution system. PowerStream further noted that the 2009 Large Use rates would need to be adjusted to reflect a different cost allocation than the current one which is based on one customer making very limited use of PowerStream's distribution system. In the absence of an updated cost allocation study, PowerStream stated that the cost of serving these two customers would be best approximated by the GS>50 kW revenue allocated to them.

Accordingly, PowerStream re-calibrated the rates for the Large Use class by transferring the billing determinants and revenues associated with these two customers. Conversely, the billing determinants and revenues were removed from the GS>50 kW rate class. PowerStream indicated that this process was revenue neutral as the revenue allocated to the Large Use class is offset by a reduction to the GS>50 class of the same amount.

Board staff identified several concerns with PowerStream's proposal.

Board staff noted that the proposed rate adjustments may not be revenue neutral at the customer level as a result of blending the revenues associated with the two GS>50 kW customers with the revenue of the existing Large Use customer to derive a single set of rates that would be applicable to all three customers. Board staff estimated that the impact on the existing Large Use customer would be an increase of approximately $96,000 per year or an increase of about 86% of the distribution component of the customer's bill.

Board staff also noted that no evidence was provided to support the reasonability of using the revenue associated with the existing GS>50 kW as a proxy of the costs that would have been allocated to the Large Use class were a cost of service study conducted that would reflect the characteristics of these customers. Staff further noted that it was unclear whether it is appropriate to include these two customers in the Large Use rate class given the specific characteristics of the existing customer currently in that class.

Board staff submitted that the Board may wish to consider denying PowerStream's request pending a full review of this matter.

In its reply submission, PowerStream stated it would be prepared to accept Board staff's submission and postpone the adjustments to Large Use distribution rates pending an updated Cost Allocation Study. PowerStream agreed that the proposed Large Use rates were approximated, and may not accurately reflect the cost of serving those customers. PowerStream added that the current distribution rate for the Large Use class is customer-specific and thus does not reflect the costs of serving any future customers that could be classified as Large Use based on their load characteristics. Therefore, to ensure the fair treatment of all customers, PowerStream submitted that any new or existing customers with average monthly demand of 5,000 kW or greater be treated as GS> 50 customers until such time as rates for the Large Use class are revised based on a Cost Allocation Study reflecting the change in the composition of Large Use customers. Based on a January 2010 review of customer consumption levels, PowerStream identified a single customer that has an average demand in excess of 5,000 kW. This customer would not be reclassified to the Large Use class.

The Board agrees with the concerns expressed by Board staff and accepts the interim solution presented by PowerStream that any new or existing customers with average monthly demand of 5,000 kW or greater be treated as GS> 50 kW customers until such time as rates for the Large Use class are revised based on a Cost Allocation Study reflecting the change in the composition of Large Use customers.

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”). There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral 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., deferral accounts 1584 and 1586).

On May 28, 2009, the Board issued its Decision and Rate Order in proceeding EB-2008-0272, which set new UTRs for Ontario transmitters, effective July 1, 2009. The new UTRs effective July 1, 2009 were as follows:

- Network Service Rate was increased from $2.57 to $2.66 per kW per month, a 3.5% increase;
- Line Connection Service Rate remained unchanged at $0.70 per kW per month; and

- Transformation Connection Service Rate was decreased from $1.62 to $1.57 per kW per month, for a combined Line and Transformation Connection Service Rates reduction of 2.2%.

On July 22, 2009 the Board issued an amended “Guideline for *Electricity Distribution Retail Transmission Service Rates*” (“RTSR Guideline”), which provided electricity distributors with instructions on the evidence needed, and the process to be used, to adjust RTSRs to reflect the changes in the UTRs effective July 1, 2009. The Board set as a proxy at that time an increase of 3.5% for the Network Service Rate and reduction of 2.2% for the combined Line and Transformation Connection Service Rates. The Board also noted that there would be further changes to the UTRs in January 2010. The objective of resetting the rates is to minimize the prospective balances in deferral accounts 1584 and 1586.

On January 21, 2010, the Board approved new UTRs effective January 1, 2010. The new UTRs were as follows:

- Network Service Rate has increased from $2.66 to $2.97 per kW per month, an 11.7% increase over the July 1, 2009 level or 15.6% over the rate in effect prior to July 1, 2009;
- Line Connection Service Rate has increased from $0.70 to $0.73 per kW per month; and
- Transformation Connection Service Rate has increased from $1.57 to $1.71 per kW per month, for a combined Line and Transformation Connection Service Rates increase of 7.5% over the July 1, 2009 level or 5.2% over the rate in effect prior to July 1, 2009.

PowerStream applied for an adjustment to its RTS rates that is based on a comparison of RTS revenue under existing rates and adjusted wholesale transmission costs. PowerStream requested an increase of 3.8% for its Network Service Rate and a decrease of 0.7% for its Line and Transformation Connection Service Rate. However, in its reply submission, PowerStream agreed with Board staff that the RTS rates should reflect the January 1, 2010 UTRs.

In its reply submission, in accordance with the July 22, 2009 RTSR Guideline, PowerStream updated the calculations of its RTS rates to reflect the changes from the current level (i.e. rate in effect prior to July 1, 2009) to the January 1, 2010 level.

PowerStream proposed an increase of 10.9% for its Network Service Rate and an increase of 3.9% for its Line and Transformation Connection Service Rate. The Board finds that PowerStream has provided a reasonable analysis and accepts the methodology used by PowerStream to reset its RTSRs. The Board approves the revised RTSRs proposed by PowerStream and will include these in the draft Rate Order.

Review and Disposition of Group 1 Deferral and Variance Accounts

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed of 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 of.

PowerStream did not request a disposition of the Group 1 account balances because it had not exceeded the disposition threshold. Board staff submitted that PowerStream had demonstrated that it is not required to dispose of those account balances. The Board agrees that a disposition of PowerStream's Group 1 account balances is not required at this time.

Introduction of MicroFit Generator Service Classification and Rate

Ontario's Feed-In Tariff (FIT) program for renewable energy generation was established in the *Green Energy and Green Economy Act, 2009*. The program includes a stream called Micro FIT, which is designed to encourage homeowners, businesses and others to generate renewable energy with projects of 10 kilowatts (kW) or less.

In its EB-2009-0326 Decision and Order, issued February 23, 2010, the Board approved the following service classification definition, which is to be used by all licensed distributors:

microFIT Generator

> *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.*

On March 17, 2010, the Board approved a province-wide fixed service charge of $5.25 per month for all electricity distributors effective September 21, 2009.

The microFIT Generator service classification and the service charge will be included in the Tariffs of Rates and Charges.

Rate Model

The Board is providing PowerStream with a rate model (spreadsheet) 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 2009 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

1. PowerStream's new distribution rates shall be effective May 1, 2010.

2. PowerStream shall review the draft Tariff of Rates and Charges set out in Appendix A. PowerStream 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 seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by PowerStream to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

3. The draft Tariff of Rates and Charges set out in Appendix A of this order will become final, effective May 1, 2010, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2010.

If the Board receives a submission by PowerStream to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of PowerStream and will issue a final Tariff of Rates and Charges.

4. PowerStream shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

5. Pursuant to section 30 of the Ontario Energy Board Act, 1998, PowerStream shall pay the Board's costs of and incidental to, this proceeding immediately upon receipt of the Board's invoice.

DATED at Toronto, April 6, 2010
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

EB-2009-0246

April 6, 2010

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.87
Smart Meter Funding Adder	$	1.81
Distribution Volumetric Rate	$/kWh	0.0134
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0002)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	(0.0023)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	28.34
Smart Meter Funding Adder	$	1.81
Distribution Volumetric Rate	$/kWh	0.0115
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0001)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	(0.0024)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 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, 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	83.56
Smart Meter Funding Adder	$	1.81
Distribution Volumetric Rate	$/kW	3.4668
Low Voltage Service Rate	$/kW	0.0472
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0233)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(0.9971)
Retail Transmission Rate – Network Service Rate	$/kW	2.1613
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9107

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	2,150.80
Smart Meter Funding Adder	$	1.81
Distribution Volumetric Rate	$/kW	1.0374
Low Voltage Service Rate	$/kW	0.0558
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0082)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(1.7100)
Retail Transmission Rate – Network Service Rate	$/kW	2.5356
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0763

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is 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 customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.17
Distribution Volumetric Rate	$/kWh	0.0086
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0003)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.98
Distribution Volumetric Rate	$/kW	9.2931
Low Voltage Service Rate	$/kW	0.0401
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0679)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(2.8005)
Retail Transmission Rate – Network Service Rate	$/kW	1.6516
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7722

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

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 operation, 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.

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.83
Distribution Volumetric Rate	$/kW	4.8105
Low Voltage Service Rate	$/kW	0.0367
Rate Rider for Tax Change – effective until April 30, 2011	$/kW	(0.0595)
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	(0.8317)
Retail Transmission Rate – Network Service Rate	$/kW	1.6351
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7081

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component – effective September 21, 2009

Service Charge	$	5.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$	(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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	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
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
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary Service install and remove – overhead – no transformer	$	500.00

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0246

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

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

Ontario

EB-2009-0245

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 Barrie Hydro Distribution Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2010.

BEFORE: Paul Vlahos
Presiding Member

DECISION AND ORDER

Introduction

Barrie Hydro Distribution Inc. ("Barrie Hydro"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2010.

Barrie Hydro is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2008, the Board announced the establishment of a new multi-year electricity distribution rate-setting plan, the 3rd Generation Incentive Rate Mechanism ("IRM") process, that will be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review.

As part of the plan, Barrie Hydro is one of the electricity distributors that will have its rates adjusted for 2010 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 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on July 14, 2008, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008, and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (together the "Reports"). Among other things, the Reports contained the relevant guidelines for 2010 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process. On July 22, 2009 the Board issued an update to Chapter 3 of the Board's "Filing Requirements for Transmission and Distribution Applications" (the "Filing Requirements"), which outlined the filing requirements for IRM applications by electricity distributors.

Notice of Barrie Hydro's rate application was given through newspaper publication in Barrie Hydro'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. There were no intervention requests and no comments were received. Board staff participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, 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;
- Changes in the Federal and Provincial Income Tax Rates;
- Harmonized Sales Tax;
- Smart Meter Funding Adder;
- Revenue-to-Cost Ratios;

- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Accounts; and
- Introduction of MicroFIT Generator Service Classification and Rate.

Price Cap Index Adjustment

Barrie Hydro's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Barrie Hydro, the Board has applied the policies described in the Reports.

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 Barrie Hydro's utility specific stretch factor of 0.2%. Based on the final 2009 data published by Statistics Canada, the Board has established the price escalator to be 1.3%. The resulting price cap index adjustment is therefore 0.38%. The Board has adjusted the rate model to reflect the newly calculated price cap index adjustment. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.

The price cap index adjustment will not apply to the following components of distribution 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; and
- Retail Service Charges.

Changes in the Federal and Provincial Income Tax Rates

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic Outlook and Fiscal Review (the "Fiscal Review"). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

The Federal Budget which was presented on January 27, 2009 and received Royal Assent on March 12, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009.

On March 26, 2009, the Ontario provincial budget was presented and Bill 218, the enabling legislation, received Royal Assent on December 15, 2009. For corporations, the basic income tax rates will decrease in stages from 14% to 10% by July 1, 2013, while on July 1, 2010, the small business rate will drop from 5.5% to 4.5%, after the small business deduction is made where applicable. A provincial small business surtax claws back the benefit of the small business deduction when taxable income of associated corporations exceeds $500,000 and eliminates the benefit completely once taxable income, on an associated basis, reaches $1,500,000. The surtax will be eliminated on July 1, 2010.

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[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15 million effective January 1, 2008.

The following table summarizes past, current and impending tax changes.

Tax Rates **Federal & Provincial** **As of December 15, 2009**	**Effective January 1, 2009**	**Effective January 1, 2010**	**Effective January 1, 2011**	**Effective January 1, 2012**	**Effective January 1, 2013**	**Effective January 1, 2014**
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Surtax (4% of line 3)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-9.00%	-10.00%	-11.50%	-13.00%	-13.00%	-13.00%
	19.00%	18.00%	16.50%	15.00%	15.00%	15.00%
Ontario income tax	14.00%	13.00%	11.75%	11.25%	10.50%	10.00%
Combined federal and Ontario	**33.00%**	**31.00%**	**28.25%**	**26.25%**	**25.50%**	**25.00%**
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	5.50%	5.00%	4.50%	4.50%	4.50%	4.50%
Ontario surtax claw-back of 4.25% (eliminated July 1, 2010) starts at $500,000 and eliminates the SBC at $1,500,000.						
Ontario surtax	4.25%	2.125%	0.00%	0.00%	0.00%	0.00%
Ontario Capital Tax						
Capital deduction	15,000,000	15,000,000	0	0	0	0
Capital tax rate	0.225%	0.075%	0.0%	0.0%	0.0%	0.0%
OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.						

The Board is of the view that these tax changes when combined could be material and should be reflected in rates using a 50/50 sharing as determined by the Board in the Reports. Therefore the incentive regulation rate model shall be adjusted accordingly.

Harmonized Sales Tax

The 8% Ontario provincial sales tax (“PST”) and the 5% Federal goods and services tax (“GST”) will be harmonized effective July 1, 2010, at 13%, pursuant to Ontario Bill 218 which received Royal Assent on December 15, 2009.

The PST is currently included in a distributor's OM&A expenses and capital expenditures. The PST is therefore included in the distributor's revenue requirement and is recovered from ratepayers through distribution rates.

When the PST and GST are harmonized, distributors will pay the HST on purchased goods and services but will claim an input tax credit ("ITC") for the PST portion. Therefore, the distributor will no longer incur that portion of the tax that was formerly applied as PST.

Board staff submitted that the Board may wish to consider the establishment of a deferral account to record the amounts, after July 1, 2010 and until Barrie Hydro's next cost-of-service rebasing application, that were formerly incorporated as the 8% PST on capital expenditures and expenses incurred, but which will now be eligible for an ITC. This account would track the incremental change due to the introduction of the HST that incorporates an increased ITC from the current 5% to a 13% level.

Barrie Hydro commented that this process would be administratively onerous, and that this change is just one of many changes that distributors experience on a regular basis. Barrie Hydro further submitted that the Board should consider to address this issue in a generic context since this is an industry-wide issue.

The Board finds that it would not be incrementally onerous for distributors to track the ITC amounts as the distributor will need to file ITC information in GST/HST returns and go through the quantification process to satisfy the requirements by the tax authorities and that the final amounts will be confirmed by the tax authorities. In regulatory parlance, what Staff is suggesting is in the nature of a deferral account, not a variance account, and as such there is no need to compare these amounts with any reference to PST levels reflected in existing rates.

Rather, the issue in the Board's view is whether a distributor's cost reductions arising from the implementation of the HST should be returned to the ratepayers. In that regard, the Board notes that to do so would be consistent with what the Board has done with tax changes in second and third generation IRMs. In second generation IRM, the Board treated 100% of the tax changes as a Z factor. In the third generation IRM, the Board determined that tax changes would be shared equally between ratepayers and the shareholder. The 50% was considered appropriate as the changes in input prices will flow through the GDP-IPI over time to some degree. The same rationale applies in the case of the HST.

The Board therefore directs that, beginning July 1, 2010, Barrie Hydro shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)), the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of Barrie Hydro's next cost of service rate order. 50% of the confirmed balances in the account shall be returnable to the ratepayers.

The Board may issue more detailed accounting guidance in the future. In that event, the Applicant should make the appropriate accounting entries, if and as applicable.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law. Barrie Hydro is authorized conduct smart meter activities because it is covered by paragraph 8 of section 1(1) of O. Reg. 427/06.

Barrie Hydro requested to change its standard smart meter funding adder of $1.00 per metered customer per month to a utility-specific smart meter funding adder of $1.61 per metered customer per month. The Board approves the funding adder proposed by Barrie Hydro as reasonable. This new funding adder will be reflected in the Tariff of Rates and Charges. Barrie Hydro's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.61 per metered customer per month is intended to provide funding for Barrie Hydro's smart metering activities in the

2010 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Barrie Hydro applies for the recovery of these costs.

Revenue-to-Cost Ratios

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.

The Board's Decision (EB-2007-0746) for Barrie Hydro's 2008 cost of service rate application prescribed a phase-in period to adjust its revenue-to-cost ratios.

Barrie Hydro proposed to adjust its revenue-to-cost ratios as shown in Column 2 in the table below.

Barrie Hydro's Revenue-to-Cost Ratios (%)

Rate Class	**2009 Ratio** Column 1	**Proposed 2010 Ratio** Column 2	**Target Range** Column 3
Residential	115.23	113.11	85 - 115
General Service Less Than 50 kW	100.20	100.20	80 - 120
General Service 50 to 4,999 kW	80.93	80.93	80 - 180
General Service 50 to 4,999 kW - Time of Use	0.00	0.00	80 - 180
Large Use	85.68	85.68	85 - 115
Unmetered Scattered Load	98.60	98.60	80 - 120
Street Lighting	25.00	55.00	70 - 120

The Board finds that the proposed revenue-to-cost ratios are in accordance with the Board's findings in the decision referenced above. The Board therefore approves the proposed revenue-to-cost ratios.

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"). There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral 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., deferral accounts 1584 and 1586).

On May 28, 2009, the Board issued its Decision and Rate Order in proceeding EB-2008-0272, which set new UTRs for Ontario transmitters, effective July 1, 2009. The new UTRs effective July 1, 2009 were as follows:

- Network Service Rate was increased from $2.57 to $2.66 per kW per month, a 3.5% increase;
- Line Connection Service Rate remained unchanged at $0.70 per kW per month; and
- Transformation Connection Service Rate was decreased from $1.62 to $1.57 per kW per month, for a combined Line and Transformation Connection Service Rates reduction of 2.2%.

On July 22, 2009 the Board issued an amended "Guideline for *Electricity Distribution Retail Transmission Service Rates*" ("RTSR Guideline"), which provided electricity distributors with instructions on the evidence needed, and the process to be used, to adjust RTSRs to reflect the changes in the UTRs effective July 1, 2009. The Board set as a proxy at that time an increase of 3.5% for the Network Service Rate and reduction of 2.2% for the combined Line and Transformation Connection Service Rates. The Board also noted that there would be further changes to the UTRs in January 2010. The objective of resetting the rates is to minimize the prospective balances in deferral accounts 1584 and 1586.

On January 21, 2010, the Board approved new UTRs effective January 1, 2010. The new UTRs were as follows:

- Network Service Rate has increased from $2.66 to $2.97 per kW per month, an 11.7% increase over the July 1, 2009 level or 15.6% over the rate in effect prior to July 1, 2009;
- Line Connection Service Rate has increased from $0.70 to $0.73 per kW per month; and
- Transformation Connection Service Rate has increased from $1.57 to $1.71 per kW per month, for a combined Line and Transformation Connection Service Rates increase of 7.5% over the July 1, 2009 level or 5.2% over the rate in effect prior to July 1, 2009.

Barrie Hydro proposed to change the existing RTS rates by the same proportions as the changes in the UTRs noted above effective July 1, 2009. Therefore, Barrie Hydro has proposed to increase all of its RTS Network Rates by 3.5%, and decreased all of its RTS Connection Rates by 2.2%. However, in its reply submission, Barrie Hydro agreed with Board staff that the RTSR rates should reflect the January 1, 2010 UTRs.

The Board notes that very few distributors, including Barrie Hydro, included in their 2009 rates the July 1, 2009 level of UTRs since for most of them distribution rates would have been implemented on May 1, 2009. The Board also notes that Barrie Hydro agreed to reflect the January 1, 2010 UTRs. Therefore, in accordance with the July 22, 2009 RTSR Guideline, the Board finds that the revisions to the RTSRs ought to reflect the changes from the current level (i.e. rate in effect prior to July 1, 2009) over the to the January 1, 2010 level. This represents an increase of about 15.6% to the RTSR Network Service rate, and an increase of about 5.2% to the RTSR Line and Transformation Connection Service Rate. The Board will reflect these findings in Barrie Hydro's draft Rate Order.

Review and Disposition of Group 1 Deferral and Variance Accounts

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed of 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 of.

With respect to the disposition period, the EDDVAR Report states that the default position would be one year.

(i) Balances

Barrie Hydro has requested that the Board review and approve the disposition of the December 31, 2008 Group 1 account balances as defined by the EDDVAR Report since the preset disposition threshold of $0.001 per kWh was exceeded. The combined total of Group 1 account balance is a credit of $6,468,801, which includes a debit balance of $1,181,215 in the 1588 global adjustment sub-account. (Credit balances are amounts payable to customers and debit balances are amounts recoverable from customers). Barrie Hydro has included interest on these account balances using the Board's prescribed interest rates to April 30, 2010. Barrie Hydro's account balances as at December 31, 2008, plus projected carrying charges to April 30, 2010, are shown below.

Barrie Hydro's Group 1 Deferral and Variance Account Balances ($)

Account Description	Account Number	Principal Amounts A	Interest Amounts B	Total Claim C = A + B
LV Variance Account	1550	85,639	(246)	85,393
RSVA - Wholesale Market Service Charge	1580	(3,129,303)	(158,128)	(3,287,431)
RSVA - Retail Transmission Network Charge	1584	(308,521)	30,631	(277,890)
RSVA - Retail Transmission Connection Charge	1586	(374,975)	(9,352)	(384,327)
RSVA - Power (Excluding Global Adjustment)	1588	(2,892,735)	(333,264)	(3,225,999)
RSVA - Power (Global Adjustment Sub-account)	1588	1,177,810	3,405	1,181,215
Recovery of Regulatory Asset Balances	1590	(539,121)	(20,641)	(559,762)
		(5,981,206)	**(487,595)**	**(6,468,801)**

In response to an interrogatory from Board staff, Barrie Hydro stated that it had reviewed the Regulatory Audit & Accounting Bulletin 200901 and confirmed that it had accounted for its Account 1588 RSVA power and global adjustment sub-account in accordance with this Bulletin. Board staff noted that the proposed balances for disposition may no longer reconcile with previously audited balances nor with Barrie Hydro's Reporting and Record-keeping Requirements ("RRR") filings. Board staff indicated that its review of the balances showed that the differences between the applied for account balances and the previously audited balances were not material.

The Board approves the proposed balances for Group 1 accounts as presented by Barrie Hydro. The December 31, 2008 balances and projected interest to April 30, 2010 are considered final. For accounting purposes, the respective balance in each of the Group 1 accounts shall be transferred to account 1595 as soon as possible but no later than June 30, 2010 so that the Reporting and Record-keeping Requirements ("RRR") data reported in the second quarter of 2010 reflect these adjustments.

(ii) *Disposition*

The EDDVAR Report includes guidelines on the cost allocation methodology and the rate rider derivation for the disposition of deferral and variance account balances. The Board notes that Barrie Hydro followed the guidelines outlined in the EDDVAR Report and approves Barrie Hydro's proposals except for the treatment of global adjustment sub-account balance.

The EDDVAR Report adopted an allocation of the global adjustment sub-account balance based on kWh for non-RPP customers by rate class. Traditionally, this allocation would then be combined with all other allocated variance account balances by rate class. The combined balance by rate class would be divided by the volumetric billing determinants from the most recent audited year-end or Board-approved forecast, if available. This approach spreads the recovery or refund of the allocated account balances to all customers in the affected rate class.

This method was based on two premises. First, the recovery/refund of a variance unique to a subset of customers within a rate class would not be unfair to the rate class as a whole. Second, the distributors' existing billing system may not be capable of billing a subset of customers within a rate class.

Subsequent to the issuance of the EDDVAR Report, exogenous events have resulted in increased balances in the global adjustment sub-account for most electricity distributors. Board staff suggested that the Board may wish to consider establishing a separate rate rider for the disposition of the global adjustment sub-account balance enabling the prospective recovery solely from non-RPP customers, as this would be more reflective of cost causality since it was that group of customers that was undercharged by the distributor in the first place. Alternatively, Board staff suggested that the Board may wish to consider the recovery of the allocated global adjustment sub-account balance from all customers in each class, as this approach would recognize the customer migration that might occur both away from the non-RPP customer group and into the non-RPP customer group.

In response to an interrogatory by Board staff, Barrie Hydro agreed in principle with Board staff that the establishment of a separate rate rider that would be prospectively applied to non-RPP customers would be more reflective of cost causality. Barrie Hydro however noted that customer migration would remain an issue. In its reply submission, Barrie Hydro proposed to establish a separate rate rider that would prospectively apply to non-RPP customers, with the exception of any MUSH and other designated customers who were on RPP as of December 31, 2008.

The Board will adopt the proposal of Board staff that a separate rate rider be established to dispose of the global adjustment sub-account. The rate rider would apply prospectively to non-RPP customers, and would exclude any MUSH and other designated customers who were on RPP as of December 31, 2008. The Board is of the view that it is appropriate to dispose of this account balance from the customer group that caused the variance (i.e. non-RPP customers). While customer migration makes this an imperfect solution, a separate rate rider applicable to non-RPP customers would result in enhanced cost causality compared to a disposition that would apply to all customers in the affected rate classes.

Barrie Hydro requested the disposition of its Group 1 account balance over a one year period. Board staff agreed with Barrie Hydro’s proposal. The Board accepts the disposition period of one year proposed by Barrie Hydro.

Introduction of MicroFit Generator Service Classification and Rate

Ontario’s Feed-In Tariff (FIT) program for renewable energy generation was established in the *Green Energy and Green Economy Act, 2009*. The program includes a stream called Micro FIT, which is designed to encourage homeowners, businesses and others to generate renewable energy with projects of 10 kilowatts (kW) or less.

In its EB-2009-0326 Decision and Order, issued February 23, 2010, the Board approved the following service classification definition, which is to be used by all licensed distributors:

microFIT Generator

> *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.*

On March 17, 2010, the Board approved a province-wide fixed service charge of $5.25 per month for all electricity distributors effective September 21, 2009.

The microFIT Generator service classification and the service charge will be included in the Tariffs of Rates and Charges.

Rate Model

The Board is providing Barrie Hydro with a rate model (spreadsheet) 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 2009 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

1. Barrie Hydro's new distribution rates shall be effective May 1, 2010.

2. Barrie Hydro shall review the draft Tariff of Rates and Charges set out in Appendix A. Barrie Hydro 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 seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Barrie Hydro to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

3. The draft Tariff of Rates and Charges set out in Appendix A of this order will become final, effective May 1, 2010, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2010.

If the Board receives a submission by Barrie Hydro to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Barrie Hydro and will issue a final Tariff of Rates and Charges.

4. Barrie Hydro shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 1, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

EB-2009-0245

April 1, 2010

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0245

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.34
Smart Meter Funding Adder	$	1.61
Distribution Volumetric Rate	$/kWh	0.0137
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0003)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2011		
Applicable only for Non-RPP Customers	$/kWh	0.0015
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2011	$/kWh	(0.0051)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0053

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0245

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.94
Smart Meter Funding Adder	$	1.61
Distribution Volumetric Rate	$/kWh	0.0163
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2011 Applicable only for Non-RPP Customers	$/kWh	0.0015
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2011	$/kWh	(0.0050)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

GENERAL SERVICE 50 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 expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	392.52
Smart Meter Funding Adder	$	1.61
Distribution Volumetric Rate	$/kW	1.82
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0280)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2011 Applicable only for Non-RPP Customers	$/kW	0.5739
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	0.0752
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2011	$/kW	(1.8958)
Retail Transmission Rate – Network Service Rate	$/kW	2.2121
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8702

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

GENERAL SERVICE 50 to 4,999 kW TOU SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW and who has an electrical service of at least 600 amps at 600/347 volts or 1600 amps at 208/120 volts. If the customer meets these criteria then an interval meter is required. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	392.52
Smart Meter Funding Adder	$	1.61
Distribution Volumetric Rate	$/kW	1.82
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2011 Applicable only for Non-RPP Customers	$/kW	0.5739
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	0.0752
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2011	$/kW	(1.8958)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.9366
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.4827

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than or is expected to be equal to or greater than 5000 kW. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	9,588.45
Smart Meter Funding Adder	$	1.61
Distribution Volumetric Rate	$/kW	0.5855
Low Voltage Service Rate	$/kW	0.3886
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0328)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.9447
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.4896

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW. As determined by Barrie Hydro Distribution Inc. because of the type of connection or location a meter is not feasible in these situations. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility'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)	$	7.87
Distribution Volumetric Rate	$/kWh	0.0160
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.0002)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2011 Applicable only for Non-RPP Customers	$/kWh	0.0015
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2011	$/kWh	(0.0050)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
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EB-2009-0245

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	2.6572

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.32
Distribution Volumetric Rate	$/kW	8.6910
Low Voltage Service Rate	$/kW	0.2301
Rate Rider for Tax Change – effective until April 30, 2011	$/kWh	(0.1598)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2011 Applicable only for Non-RPP Customers	$/kW	0.5039
Rate Rider for Deferral/Variance Account Disposition (2009) – effective until April 30, 2011	$/kW	0.0666
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2011	$/kW	(1.6342)
Retail Transmission Rate – Network Service Rate	$/kW	1.7475
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4773

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

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 utility'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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component – effective September 21, 2009

Service Charge	$	5.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

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EB-2009-0245

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$	(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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – no disconnection	$	15.00
Disconnect/Reconnect at Meter - during Regular Hours	$	30.00
Disconnect/Reconnect at Meter - after Regular Hours	$	185.00
Disconnect/Reconnect at Pole - during Regular Hours	$	185.00
Disconnect/Reconnect at Pole - after Regular Hours	$	415.00
Service Call – customer owned equipment – charge based on time and materials		
Service Call – after regular hours – charge based on time and materials		
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010

except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0245

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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	1.0565
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0462
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Ontario Energy
Board

Commission de l' énergie
de l'Ontario

Ontario

EB-2008-0244

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 PowerStream Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Cathy Spoel
Member

MAJORITY DECISION

July 27, 2009

This is a Majority Decision by Members Paul Vlahos and Cathy Spoel. The Minority Decision by Vice Chair Gordon Kaiser follows the Majority Decision.

Background

On June 03, 2009, the Ontario Energy Board approved the terms and conditions of the Settlement Proposal dated May 19, 2009 in connection with PowerStream's application to approve just and reasonable rates for electricity distribution effective May 1, 2009. PowerStream and the intervenors settled all issues with the exception of one.

The one outstanding issue, raised by the Smart Sub-Metering Working Group, a group of seven Board-licenced companies offering smart sub-metering services to condominiums (the "SSMWG"), is whether and to what extent PowerStream should be permitted to include in distribution rates the costs and revenues associated with its condominium suite metering activities.

A one-day oral hearing was held on June 15, 2009 and written arguments were submitted by parties.

For the reasons set out below the Board approves the forecast revenues and costs of the condominium suite metering activities reflected in the 2009 revenue requirement that results from the settlement agreement.

The Issue and Relief Sought

Historically, condominium buildings have typically been treated as commercial customers with a bulk meter. The units are not individually metered and the utility has one customer, the condominium corporation.

Condominium suite metering, as offered by PowerStream, involves installing a separate meter for each condominium unit, and billing each unit owner as a residential customer; the condominium corporation is billed for the common areas. There is no bulk master meter required and there is no sub-metering taking place. The rates are regulated. As is common for residential customers, PowerStream does not charge for the cost of the meters; these are included in the costs allocated to the residential class as a whole. The cost of the condominium meter (Quadlogic) is considerably more expensive (about $680) than the standard meter for an individual single home (about $250). On the revenue side, PowerStream replaces one commercial customer with a larger number of residential customers, generating higher revenue because of the rate classification under which it bills for the same load previously billed for the bulk meter.

Smart sub-metering, as offered by members of the SSMWG, happens “behind” the bulk meter. Members of the SSMWG install the smart meters for the condominium units. The condominium corporation continues to be a commercial customer of PowerStream. Smart sub-metering allows for the allocation of the condominium corporation’s bill among the various unit owners, presumably in relation to their consumption of electricity. The rates are not regulated.

Because no contribution is required by PowerStream for the higher cost of the meter for condominium customers, the SSMWG alleges that there is a cost subsidy for these customers by the rest of PowerStream’s ratepayers and that this harms the competitive market and harms the SSMWG members.

The relief sought by the SSMWG is that the condominium activity should be performed by an affiliate of PowerStream. In the alternative, if in the utility, the condominium activity should be treated as a stand-alone program, on a fully-costed basis. Under the stand-alone categorization, revenues and costs of the condominium suite program would be segregated from the rest of the distribution business. In the event the program is less profitable than the distribution business on a fully-costed basis, revenue would be imputed thereby reducing the revenue requirement and rates for the rest of the ratepayers.

Should the Program be offered through an Affiliate?

The SSMWG accepted that under the existing legislative and regulatory framework, utilities are required, when asked, to install smart meters in condominiums but argued that it is open to the Board to require that the condominium activity should be undertaken through an affiliate.

PowerStream, Board staff and the intervenors argued that the legislative and regulatory framework clearly suggest that a utility such as PowerStream not only has the ability to carry out these activities directly through the utility as opposed to a separate subsidiary, but in fact it is required to do so. PowerStream argued that if the activity was carried out through a separate subsidiary, which is not by definition a distributor, a utility would not be meeting its requirements under the *Electricity Act*, the Regulations and the Distribution System Code.

Section 71 (1) of the *Ontario Energy Board Act, 1998* (the “Act”) states that distributors cannot carry on any business activity other than the distributing of electricity, except through an affiliate. However, section 71 (2) of the Act provides an exception to the general rule. Section 71 (2) states that a distributor may provide services in accordance with section 29.1 of the *Electricity Act, 1998* that would assist the government of Ontario in meeting its objectives in relation to electricity conservation.

Ontario Regulation 442/07, promulgated on August 1, 2007, allows licensed distributors to install smart meters in existing condominiums when the board of directors of the condominium corporation approves the installation of smart meters.

The Board’s Distribution System Code was recently amended by adding section 5.1.9 which reads as follows:

> When requested by either:
> (a) the board of directors of a condominium corporation; or
> (b) the developer of a building, in any stage of construction, on land for which a declaration and description is proposed or intended to be registered pursuant to section 2 of the Condominium Act, 1998,
>
> a distributor **shall install** smart metering that meets the functional specification of Ontario Regulation 425/06 – *Criteria and Requirements for Meters and Metering Equipment, Systems and Technology* (made under the Electricity Act).(Emphasis added).

On the basis of the existing legislative and regulatory framework, the Board accepts that it is appropriate for PowerStream to continue to carry out its condominium activities as it has and proposes to continue.

Should the Program be Stand-Alone?

The alternative relief sought by SSMWG is for the Board to treat PowerStream’s condominium suite activity as a stand-alone program, with the ratemaking framework as described above.

The legislative framework does not specify the ratemaking treatment of the condominium suite metering activity by distributors. The Board accepts that there may be a legitimate concern by the SSMWG if PowerStream and the SSMWG companies competed in the same market and if there is an undue cost subsidy of PowerStream's condominium suite metering activities. The Board deals with these two matters below.

Before doing so, the Board points out that treating an activity on stand-alone basis is not necessarily a remedy to allegations of anti-competitive behaviour and predatory pricing, the matters of concern for the SSMWG. Under the stand-alone ratemaking model, the Board's role is limited to imputing revenue, when warranted, to ensure that there is no cost subsidy for the suite metering business by the rest of the ratepayers. The Board would not regulate the pricing and offerings of the program. These would be at the discretion of the utility.

Do PowerStream and the SSMWG companies compete in the same market?

As noted above, suite metering, as offered by PowerStream, involves installing a separate meter for each condominium unit, and billing each unit owner as a residential customer; the condominium corporation is billed for the common areas. There is no bulk meter.

Also as noted above, sub-metering, as offered by members of the SSMWG, happens "behind" the distributor's bulk meter.

An existing condominium wishing to be smart metered or a developer of a new condominium building has the choice of choosing suite metering with PowerStream or sub-metering with another company, such as one of the SSMWG member companies. So, the metering market is contestable. The fact that PowerStream is allowed to carry this activity as part of its distribution business does not take away from the fact that the metering of condominium units is a contestable market. To the extent that there is a cost subsidy as the SSMWG alleges, and if material, the SSMWG may be legitimately concerned.

Is There a Cost Subsidy?

The SSMWG argued that, as PowerStream used a more expensive Quadlogic meter rather than the standard smart meters used for single unit residential customers, there is a cost subsidy or there is likely a cost subsidy since there is no customer contribution for the higher cost of the Quadlogic meter.

PowerStream on the other hand argued that the utility has an obligation to provide service that meets the applicable standards and the standard smart meter for technical reasons could only be used in about 5% of the units. Moreover, all market participants use the same Quadlogic meter for the same reasons - it is the most effective equipment to meet the requirements of condominium units. The Board accepts PowerStream's rationale for using the higher cost Quadlogic meter. The Board notes that members of the SSMWG use the same meter for its technical and other advantages in the condominium sub-metering market.

As a number of interveners note, metering costs (a capital cost) may be higher but operating costs are likely lower. PowerStream was unable to provide precise operating costs as it was not previously required to segregate costs for the condominium activity in any fashion. On the basis of the information produced, most parties argued that there is no cost subsidy but other parties conceded that there may be a cost subsidy. There was however general agreement that the information adduced was not sufficient to conclude confidently that there is a subsidy, and in which direction.

The Board agrees with that assessment. The SSMWG has not, in this case, convinced the Board that there is a cost subsidy to condominium unit customers by the other residential ratepayers and, if there is, that it is material.

On the findings and reasons above, the Majority Panel is not prepared to grant the relief requested by the SSMWG.

Which Way Forward?

The metering capital cost differentiation issue for condominium customers was first raised by Board staff in the Toronto Hydro proceeding (EB 2007-0680). (The SSMWG was not a participant in the Toronto Hydro proceeding). In that proceeding, that Board Panel stated as follows:

> *At this time, for the purposes of this Decision, the Board will not consider differentiation in metering costs to be a pivotal consideration in entertaining the separation of the existing residential class or to direct the institution of contributions, capital or otherwise.*
>
> *This is an issue that requires consideration in a more generic proceeding with appropriate notice to effected parties, directed towards rate design and cost allocation. (Decision of the Board dated May 15, 2008, EB 2007-0680 – page 20)*

The SSMWG intends to raise its issue in other rates proceedings. The Board's view is that consideration of the issue on a utility-specific basis going forward is not the best approach for two reasons. First, there are substantial differences in the rates and operating costs from one utility to the next. The conclusions drawn in one case will be of little if any value in the resolution of this matter. Second, this is clearly a matter of Board policy. The shaping of Board policy will of course need to consider this issue in the context of a number of other policy issues before the Board. In that regard, the Board will now have two decisions from rate proceedings as it considers this matter. In the Majority Panel's view, it would be advisable for the Board to take a generic approach in addressing this matter.

PowerStream's Conditions of Service and Contracts

The SSMWG argued that PowerStream's Conditions of Service and contracts (filed in the form of a Terms of Reference Letter in SSMWG Schedule 3-1) , are unclear and misleading and do not indicate that a multi-unit building has the option of bulk metering. On cross-examination the witness for PowerStream denied this was the meaning or intent of the Conditions of Service and offered to amend the Conditions of Service to clarify the wording. (TR pg 165).

On the issue of contract exclusivity, there were also some questions raised as to the clarity of provisions in the PowerStream contracts regarding the freedom of the condominium corporation to exit a contract for another service provider. Again the PowerStream witnesses indicated that the condominium corporation could choose another service provider and that there are no barriers to exit. (TR pg 77)

The Board directs that PowerStream amend its Conditions of Service and related contracts going forward in a manner that clearly reflects the intent described by the PowerStream witnesses in this hearing. PowerStream shall file, for convenience, the amended sections of the Conditions of Service and related Terms of Reference Letters or other contracts as part of its draft rate order.

Rate Base

In accepting the revenue requirement reflected in the Settlement Proposal earlier in this decision, the Board considered the argument advanced by SEC that non-revenue producing condominium suite meters should not be forming part of rate base. The Board does not accept that revenue-generation is the test for including an asset in rate base. The test is used or useful. SEC's suggestion is not consistent with the long-standing regulatory practices in this regard. Notably, as article 410 of the Board's Accounting Procedures Handbook points out, assets will be included in rate base if they have the "capacity" to contribute to future cash flows and earn income. PowerStream's asset recognition approach to condominiums is the same as that for conventional subdivisions where installations can pre-date connection and revenue producing by a considerable time period. There is no supportable basis to treat the condominium suite metering assets distinctly.

Implementation of Rates

Pursuant to the Settlement Proposal that was approved by the Board the new rates are to be effective May 1, 2009 and implemented August 1, 2009.

Given the date of this Decision, an August 1, 2009 implementation date is no longer possible. The Board authorizes PowerStream to implement the new rates September 1, 2009.

The results of the Settlement Proposal together with the Board's findings outlined in this Decision are to be reflected in a Draft Rate Order. The Board expects PowerStream to file detailed supporting material, including all relevant calculations showing the impact of the implementation of the Settlement Proposal and this Decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates, including bill impacts. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form excel spreadsheet, which can be found on the Board's website. PowerStream should also show detailed calculations of any revisions to its low voltage rate adders, retail transmission service rates and variance account rate riders reflecting the Settlement Proposal and this Decision.

A final Rate Order will be issued after the following steps have been completed.

1. PowerStream shall file with the Board, and shall also forward to the intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges and other filings reflecting the Board's findings in this Decision, within 14 days of the date of this Decision.

2. Intervenors shall file any comments on the Draft Rate Order with the Board and forward to PowerStream within 7 days of the date of filing of the Draft Rate Order.

3. PowerStream shall file with the Board and forward to intervenors responses to any comments on its Draft Rate Order within 7 days of the date of receipt of intervenor submissions.

Costs Awards

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. The Board will determine eligibility for costs in accordance with its Practice Direction on Cost Awards. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

PowerStream and CCC requested that costs of this proceeding should be assessed against the SSMWG on the basis that this was not the appropriate forum to raise that issue. Having accepted the SSMWG's issue for consideration in this proceeding, the Board does not find it appropriate to assess costs against the SSMWG.

A cost awards decision will be issued after the following steps have been completed.

1. Intervenors found eligible for cost awards shall file with the Board, and forward to PowerStream, their respective cost claims within 30 days from the date of this Decision.

2. PowerStream shall file with the Board and forward to intervenors any objections to the claimed costs within 44 days from the date of this Decision.

3. Intervenors shall file with the Board and forward to PowerStream any responses to any objections for cost claims within 51 days of the date of this Decision.

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

DATED at Toronto, July 27, 2009

ONTARIO ENERGY BOARD

Original Signed By

____
Paul Vlahos
Member

Original Signed By

____
Cathy Spoel
Member

MINORITY DECISION

I have had the benefit of reading the reasons of the majority. I agree that PowerStream should be granted the rate relief requested but would add two conditions. The first is that PowerStream file a study that identifies the costs and revenues of its condominium smart meter service. The second is that the contracts between PowerStream and the condominium corporation relating to this service be amended to indicate that the contracts can be terminated on 90 days notice without penalty.

Background

On June 3, 2009, the Ontario Energy Board approved the terms and conditions of the Settlement Proposal filed by PowerStream Inc. in connection with PowerStream's application to approve just and reasonable rates for electricity distribution effective May 1, 2009.

The Applicant and the intervenors settled all issues with the exception of one. The one outstanding issue is whether and to what extent PowerStream should be permitted to recover in rates the operating and capital costs of its smart metering activities in condominiums. That issue is the subject of this decision.

PowerStream's request is supported by Board staff and all intervenors with one exception. The opposing intervenor is the Smart Sub-Metering Working Group (the "Working Group"). The Working Group consists of eight licensed smart submetering companies that compete with PowerStream in providing Smart Meters to condominium residents.

It is accepted that the market for this service is competitive. All nine companies appear to supply essentially the same service using similar, if not identical equipment.

The Working Group argues that the costs PowerStream is seeking to recover should not be recovered in rates. Instead, they argue that PowerStream should deliver these services through a separate subsidiary or alternatively through the utility but by using a non utility account which means that expenses are not recovered in rates.

The Regulatory Framework

As a general rule, the Board requires utilities to carry out competitive activities through a separate subsidiary. There are two reasons for this approach. First, there is a concern that the utility will subsidize the competitive activities from revenues received from monopoly services. This works to the disadvantage of ratepayers of monopoly services. Second, it may provide a utility with an unfair competitive advantage in the marketplace if monopoly revenues are used to subsidize the competitive services.

In the case of conservation activities such as smart metering, however special provisions apply. The relevant exemption is set out in section 71 (2) of the *Ontario Energy Board Act, 1998.*

> **Restriction on business activity**
>
> **71.** (1) Subject to subsection 70 (9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity. 2004, c. 23, Sched. B, s. 12.
>
> **Exception**
>
> (2) Subject to section 80 and such rules as may be prescribed by the regulations, a transmitter or distributor may provide services in accordance with section 29.1 of the *Electricity Act, 1998* that would assist the Government of Ontario in achieving its goals in electricity conservation, including services related to,
>
> (a) the promotion of electricity conservation and the efficient use of electricity;
>
> (b) electricity load management; or
>
> (c) the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. 2004, c. 23, Sched. B, s. 12

PowerStream and most intervenors argued that these sections clearly indicate that a utility such as PowerStream has the ability to carry out these activities directly through the utility as opposed to a separate subsidiary. I accept this interpretation.

This leaves open the alternative relief sought by the Working Group which is that the activities could be carried out through the utility but through a non-utility account which means that the expenses cannot be recovered in rates.

Anti Competitive Conduct

The Working Group is concerned that if utilities are allowed to carry out these activities through the regulated entity they will be able to subsidize competitive services by monopoly revenues and eliminate competitors.

While the Legislation states that utilities can carry out these activities through the regulated entity, there is no indication that the Legislature intended to promote or condone anti-competitive conduct. I believe that the intent of the legislation was to promote competitive markets with a large number of suppliers in order to best promote the rapid introduction of this technology. Put differently, utilities were allowed to enter the market directly to promote competition, not lessen it.

The concern of the Working Group is understandable, but is there any evidence of anti-competitive conduct in this case?

The evidence is inconclusive. On the one hand, the Working Group relies upon the differences in capital cost. They argue for example that the cost of the Quadlogic meter used by PowerStream is significantly more expensive than the meter used for most residential customers. That may be, but as PowerStream argues the utility has an obligation to provide service that meets the applicable standards and the standard meter for technical reasons could only be used in about 5% of the units. Moreover, the competitors all use the same meter for the same reasons - it is the most effective equipment to meet the requirements of condominium units.

In addition, as a number of intervenors note, capital costs are just part of the equation. In the case of operating costs, PowerStream is unable to provide a precise allocation. The utility is not able to differentiate the operating costs applicable to condominium units as opposed to other residential units. As a result, the Board is unable to determine whether there has been cross subsidization or any anti-competitive impact.

To be clear, PowerStream is not being accused of predatory pricing. This is not a situation where PowerStream is designing a special rate with a view to eliminating competition. PowerStream is simply applying the existing approved residential rate of $13.23 per month to the residents of the condominium units. This is the rate monopoly customers with smart meters currently pay.

PowerStream and many of the intervenors argue that the residential class is a broad class and there are invariably subsidies flowing between various members of that class. In other words, the Board usually ignores subsidies between members of such a broad rate class. But that principle, with respect, applies to monopoly services.

This is a competitive service and the usual protection for competitors (that utilities provide competitive services through a separate affiliate) is not available given the specific statutory exemption. In the circumstances, it is important that the Board be able to determine if revenues are covering costs.

One solution is to require the utility to segregate the costs and revenues of this particular service. With the proper cost allocation, the Board and the parties will be able to determine if revenues are covering costs. Or put differently, are competitive services being subsidized by monopoly revenues?

Some intervenors argue that if the Board wishes to adopt this approach it should be done in a generic proceeding sometime in the future. The intervenors point to the recent Toronto Hydro decision where the Board adopted that approach in this exact situation. There, the Board stated at page 20:

> *At this time, for the purposes of this Decision, the Board will not consider differentiation in metering costs to be a pivotal consideration in entertaining the separation of the existing residential class or to direct the institution of contributions, capital or otherwise*
>
> *This is an issue that requires consideration in a more generic proceeding with appropriate notice to effected parties, directed towards rate design and cost allocation. (Decision of the Board dated May 15, 2008, EB-2007-0680)*

A generic decision is often the preferred solution but it cannot be an excuse for delay. This is the second time the Board has faced this issue. Moreover, it is not clear that this is necessarily a generic issue. All Ontario utilities will not be providing this service. And, we have heard that other utilities intend to carry out this activity through a separate subsidiary.

This is an important service. Installation of smart meters in individual condominium units offers significant gains in energy conservation. The Legislature has signaled the advantage of competing suppliers and specifically allowed regulated utilities to engage in the service directly. Implicit in this direction is a belief that competing suppliers will promote price competition and improve service quality.

It is also significant that this is a new market with new competitors. It would be unfortunate (and contrary to the public interest) if competitors were disadvantaged or even eliminated in the early days of this market. Repeating what the Board stated in Toronto Hydro is not, in my view, a satisfactory approach.

I accept that utilities such as PowerStream should be entitled to recover the cost of this competitive service in rates and should not be required to conduct the business through a separate subsidiary.

However, as a condition of granting this relief to PowerStream, I would require PowerStream to file within four months, a cost allocation methodology for this new service with estimates of the costs and revenues incurred to date in a manner that will allow the Board and the parties to determine whether revenues are covering costs. The Working Group will then be able to deal with this matter in PowerStream's rate application next year or through a motion for alternative relief in the event the facts warrant further action.

This process will not affect the rate recovery ordered by this decision. The Board has found that PowerStream may recover all of the costs of its condominium smart meters. Those rates are effective May 1, 2009 and run to May 1, 2010.

It may be that revenues are covering costs and there is no basis for any further action let alone a generic proceeding. It's likely that the costs and revenues of this service are similar for all utilities. All utilities have similar residential rates and the cost of installing smart meters in condominiums is not likely to differ from utility to utility in a material fashion. The evidence in this proceeding that both the utility and competitors use virtually identical equipment.

I do not believe that the condition I would attach to the rate order in any way compromises a generic initiative in the event the Board decides to pursue it. In a generic proceeding this information will be required in any event. If the Board elects not to implement a generic proceeding, the competitors will at least have the information necessary to argue the issue in a meaningful fashion.

In my view the competitors are entitled to have their argument heard. It cannot be heard in any meaningful fashion without an accurate accounting of costs and revenues relating to this service. This information is within the complete control of the utility and to date the utility has elected not to provide it.

This is not simply a question of fairness to private interests. There is also an important public interest aspect. The goal here is to encourage conservation. The seven competitors include one of the Province's largest gas distribution utilities, a useful addition to the conservation initiative in electricity markets. There can be little doubt that the entire legislative scheme with respect to this issue is designed to promote increased investment in this activity. I doubt that any of these companies, much less the gas distributors, will make a long-term commitment to this market unless they are confident there will be a level playing field.

The conservation agenda is important to the Board and the Government. Confusion and delay regarding regulatory rules is not helpful. The required cost allocation will ensure that the necessary fact-finding aspect of this issue moves forward on a timely basis.

Contract Exclusivity

The contracts used by PowerStream were placed before the Board. The Working Group argued that on their face the contracts grant PowerStream exclusivity. In other words, once the condominium had entered into a PowerStream agreement they are not free to shift to a competing vendor and the utility has locked up the market.

While the contracts are less than clear on their face, the testimony of the PowerStream witnesses clearly indicates the condominium corporation can choose to exit the contract at any time for another service provider. There are no exit fees and PowerStream, in the event the condominium chooses to terminate the contract, would simply remove the individual sub-metering equipment and deploy it elsewhere. The Board believes however that PowerStream should clarify its contract to clearly indicate the basis on which a condominium corporation can terminate service.

A monopoly utility has inherent advantages in a competitive market such as this. The PowerStream brand itself is a powerful advantage. These are long-term contracts in a newly emerging market. It is not in the public interest to allow a dominant supplier to lock up the market with long-term exclusive agreements. The PowerStream contract should be amended to clearly state that customers can terminate the contract on 90 days notice without penalty.

The utility agrees that this is the intent of the existing agreement. It is important that customers clearly understand the contract terms. They should not be required to read transcripts or regulations. There is no question that the Board has authority to require amendments to contract terms where those contracts are integral to rate regulated services[1].

DATED at Toronto, July 27, 2009

ONTARIO ENERGY BOARD

Original Signed By

Gordon Kaiser
Presiding Member and Vice-Chair

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[1] Re The Interim Contract Carriage Arrangements of Consumers Gas Company Ltd., Northern and Central Gas Corporation, and Union Gas Limited, E.B.R.O. 410, 411, 412, (April 4, 1986) at page 182.

Draft Rate Order

July 31, 2009

Table of Contents

I. Summary

PowerStream Inc. submits the following Draft Rate order, including a Proposed 2009 Tariff of Rates and Charges (attached Schedule A), as directed by the Ontario Energy Board (the “Board”) in its Majority Decision dated July 27, 2009.

In its Procedural Order No. 5, dated June 3, 2009, the Board approved the Settlement Proposal as filed May 29, 2009 by PowerStream and the Intervenors.

On June 15, 2009, the Board heard arguments on the unsettled sub-issue regarding PowerStream’s individual smart suite metering program. The Board ruled in the July 27, 2009 Decision that no adjustments are required to the amounts in the Settlement Proposal (“Settlement Agreement”) that the Board approved on June 3, 2009.

The Application’s calculations have been updated to reflect the Board’s Decision.

The Settlement Agreement is attached as Schedule H. The schedules previously filed with the Settlement Proposal have not been included as these are either unchanged or superseded by the schedules included in this draft rate order.

The impact on PowerStream’s revenue requirement is summarized in Table 1 below.

Table 1: PowerStream 2009 Revenue Requirement ($000)

	As Proposed	As per Decision	Difference	Explanation
Cost of Power	453,445	421,634	(31,811)	Settement Agreement, Issue 2.1
Net Fixed Assets	459,051	457,087	(1,964)	
Working capital	74,781	69,728	(5,054)	
Total Rate Base	**533,832**	**526,814**	**(7,018)**	
Long-term debt Cost Rate (%)	5.89%	5.89%	0.00%	As per OEB letter of Feb 24, 2009; Settlement Agreement Issue 6.1
Short-term debt Cost Rate (%)	3.67%	1.33%	-2.34%	
Common Equity Cost Rate (%)	8.40%	8.01%	-0.39%	
Cost of capital	6.81%	6.56%	-0.25%	
Return on Rate Base	36,336	34,543	(1,793)	
OM&A Expenses	43,713	41,831	(1,882)	Settement Agreement, Issue 4.1
Property Taxes	1,385	1,385	-	
Depreciation and Amortization	36,540	36,243	(297)	Settement Agreement, Issue 2.1
PILS	8,898	7,129	(1,770)	Settement Agreement, Issue 4.7
Service Revenue Requirement	126,872	121,131	(5,741)	
Revenue offsets	6,568	6,568	-	
Base Revenue Requirement	**120,304**	**114,563**	**(5,741)**	

The approved revenue requirement of $114.6 million is allocated between customer classes, to calculate the 2009 distribution rates (Settlement Agreement, Issues 7.1, 7.2, 8.1 and 8.2). The revenue validation table is provided in Schedule D.

PowerStream has updated the amounts for disposition of Regulatory Liabilities and corresponding rate riders to reflect the Board approved amount of $28.1 million and it will be refunded over the period September 1, 2009 to April 30, 2011 (Settlement Agreement, Issues 5.1 and 8.6).

PowerStream has updated the calculation of the Smart Meter Actual Cost Recovery Rate Adder to reflect the calculation that was provided to the parties at the Settlement conference. (Settlement Agreement, Issue 8.7) After filing of the Settlement Proposal, a formulaic error was discovered in Schedule G, Smart Meter Actual Cost Recovery Calculation, such that the resulting amount of $846,738 to be recovered was overstated. The corrected calculation resulted in an amount to be recovered of $571,486 (attached revised Schedule G), which has been used in preparing the 2009 proposed rates in this Draft Rate order. Table 2 below shows the Smart Meter rate riders.

Table 2: Smart Meter Rate Riders

Monthly Rate Rider	**As proposed**	**As per decision**
Future Cost Recovery	$1.04	$1.04
Actual Cost Recovery	$(0.19)	$ 0.19
Total	$0.85	$1.23

The Board approved an effective date of May 1, 2009 and an implementation date of September 1, 2009. This is discussed further in section II. Rate Implementation below.

PowerStream has completed the OEB Revenue Requirement Work Form (attached Schedule B). Table 2 below shows selected bill impacts.

Table 2: Selected Delivery Charge and Bill Impacts

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order								
		Monthly Delivery Charge					**Total Bill**			
			Per Draft	Change				Per Draft	Change	
		Current	Rate Order	$	%		Current	Rate Order	$	%
Residential	**1000** kWh/month	$ 33.79	$ 32.61	-$ 1.18	-3.5%		$ 114.14	$ 112.65	-$ 1.49	-1.3%
GS < 50kW	**2000** kWh/month	$ 66.19	$ 62.84	-$ 3.35	-5.1%		$ 234.85	$ 230.83	-$ 4.02	-1.7%

See Schedule I for additional bill impact calculations.

II. RATE IMPLEMENTATION

There is a four month delay between the May 1, 2009 effective date of PowerStream's approved 2009 distribution rates and the implementation date of September 1, 2009. To account for this delay, PowerStream has made the adjustments discussed in Section II to arrive at the proposed rates.

Forgone Revenue Rate Rider:

PowerStream has calculated a "foregone revenue rate rider" to recover the revenue that will be foregone from May 1, 2009 to August 31, 2009 as result of the September 1, 2009 implementation date, over the remaining 2009 rate year to April 30, 2010.

The amount of foregone revenue by customer class has been calculated by comparing revenue at current rates to revenue at the proposed rates for each class using the billing determinants for the four month delay period. Due to the size of the adjustment, the rate riders were calculated on a volumetric charge basis only, rather than split between fixed and volumetric. The rate riders were calculated by dividing the foregone revenue by the 2009 total kWh or kW billing determinants (net for the remaining 8 months after removing the effect of the four months May to August 2009) to arrive at the kWh or kW rate rider, for each customer class.

See Schedule C for the detailed calculation of the foregone revenue and rate riders.

Smart Meter Actual Cost Recovery Rate Rider:

The Board approved the recovery of the actual cost of Smart Meters installed up to December 31, 2007. The Smart Meter Actual Cost Recovery amount was calculated as $0.19 per month per metered customer based on a twelve month recovery period. This has been adjusted to $0.29 per month per metered customer to reflect that the recovery will take place over eight months, as shown in Table 3 below.

Table 3: Smart Meter Actual Cost Recovery Rate Rider Calculation

	Approved Amount	Average Metered Customers	Months	Actual Cost Recovery Adder
Per settlement	$ 571,486.00	249,355	12	$ 0.19
Rate Adder (sunset date: April 30, 2010)	$ 571,486.00	249,355	8	$ 0.29

LRAM/SSM Rate Rider:

The Board approved the application of a Lost Revenue Adjustment Mechanism and Shared Savings Mechanism (LRAM/SSM) amount based on the results of its 3rd tranche Conservation and Demand Management programs up to December 31, 2007. In the application, these were converted to rate riders for recovery over a twelve month period. These have been recalculated for recovery over the eight months, September 1, 2009 to April 30, 2010. Please see Schedule E for the calculation of the LRAM/SSM rate riders.

Regulatory Asset Recovery Rate Rider:

The Board approved the clearance of the December 31, 2007 Variance and Deferral account balances over a period of two years. These have been recalculated for recovery over the twenty months, September 1, 2009 to April 30, 2011.

Please see Schedule F for the calculation of the Regulatory Asset Recovery rate riders.

There is a single customer in the Large Use class and the amount to be repaid is attributable to that customer. To avoid negative variable charges in the Large Use class, PowerStream will refund the amount of $236,189 as a separate fixed credit to the existing customer's monthly bill over the recovery period. Based on a September 1, 2009 implementation date and 20 months recovery period, PowerStream will credit this customer monthly for $11,809.45 until the entire amount of $236,189 is repaid.

Other Changes:

No adjustments are proposed for the delay in implementing the new Low Voltage charges, Retail Transmission Rates, Rural Rate Protect charge and loss factors, as any differences will be tracked in the existing deferral and variance accounts for future settlement.

III. OTHER MATTERS

PowerStream has calculated Low Voltage ("LV") charges in the amount of $860,000 (revised from $1,405,000 as originally filed) based on an updated estimate using Hydro One's proposed rates for May 1, 2009. PowerStream has calculated the LV charges included in the 2009 proposed rates as shown in Schedule J.

The Board directed PowerStream to amend its Conditions of Service and related contracts to clearly reflect the intent with respect to smart suite metering as described by the PowerStream witnesses in the hearing and to include the amended sections as part of the draft rate order. The amended sections are attached as Schedule K.

PowerStream Inc.

DRAFT TARIFF OF RATES AND CHARGES

Effective May 1, 2009
Implementation September 1, 2009

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

EB-2008-0244

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2009 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT –September 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service.

General Service Less Than 50 kW

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.

General Service 50 to 4,999 kW

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.

Large Use

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.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is 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 customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting

This classification refers to an unmetered lighting load supplied to a sentinel light.

PowerStream Inc.

DRAFT TARIFF OF RATES AND CHARGES

Effective May 1, 2009
Implementation September 1, 2009

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

EB-2008-0244

Street Lighting

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, 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.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.85
Distribution Volumetric Rate	$/kWh	0.0135
Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kWh	0.0002
LRAM/SSM Rate Rider (effective until April 30, 2010)	$/kWh	0.0001
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kWh	(0.0023)
Smart Meter Future Cost Recover Rate Adder	$	$1.04
Smart Meter Actual Revenue Recovery Rate Adder (effective until April 30, 2010)	$	$0.29
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	28.29
Distribution Volumetric Rate	$/kWh	0.0116
Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kWh	0.0001
LRAM/SSM Rate Rider (effective until April 30, 2010)	$/kWh	0.0001
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kWh	(0.0024)
Smart Meter Future Cost Recover Rate Adder	$	$1.04
Smart Meter Actual Revenue Recovery Rate Adder (effective until April 30, 2010)	$	$0.29
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0022
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	83.41
Distribution Volumetric Rate	$/kW	3.5078
Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kW	0.1238
LRAM/SSM Rate Rider (effective until April 30, 2010)	$/kW	0.0441
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kW	(0.9971)
Smart Meter Future Cost Recover Rate Adder	$	$1.04
Smart Meter Actual Revenue Recovery Rate Adder (effective until April 30, 2010)	$	$0.29
Retail Transmission Rate – Network Service Rate	$/kW	1.9489
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8765
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	2,146.94
Distribution Volumetric Rate	$/kW	1.0913

PowerStream Inc.

DRAFT TARIFF OF RATES AND CHARGES

Effective May 1, 2009
Implementation September 1, 2009

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EB-2008-0244

Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kW	(0.5937)
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kW	0.0000
Smart Meter Future Cost Recover Rate Adder	$	$1.04
Smart Meter Actual Revenue Recovery Rate Adder (effective until April 30, 2010)	$	$0.29
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.2864
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.0359
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	14.14
Distribution Volumetric Rate	$/kWh	0.0087
Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kWh	(0.0017)
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	1.98
Distribution Volumetric Rate	$/kW	9.3165
Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kW	1.7282
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kW	(2.8005)
Retail Transmission Rate – Network Service	$/kW	1.4893
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7432
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.83
Distribution Volumetric Rate	$/kW	4.8386
Foregone Distribution Revenue Rate Rider (effective until April 30, 2010)	$/kW	0.7195
Regulatory Asset Recovery Rate Rider (effective until April 30, 2011)	$/kW	(0.8317)
Retail Transmission Rate – Network Service Rate	$/kW	1.4744
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6815
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

Implementation September 1, 2009

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

EB-2008-0244

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	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
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 Charges - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charges - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Temporary service install & remove – overhead – no transformer	$	500.00
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)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream (1)

File Number: EB-2008-0244

Rate Year: 2009

Version: ***1.0***

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

		Data Input				(1)
		Application		**Adjustments**	**Per Board Decision**	
1	**Rate Base**					
	Gross Fixed Assets (average)	$921,136,105	**(4)**	($3,785,331)	$917,350,774	
	Accumulated Depreciation (average)	($462,085,096)	**(5)**	$1,820,985	($460,264,111)	
	Allowance for Working Capital:					
	Controllable Expenses	$45,098,300	(6)	($1,882,000)	$43,216,300	
	Cost of Power	$453,444,524		($31,810,775)	$421,633,749	
	Working Capital Rate (%)	15.00%			15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$111,346,434			$111,346,434	
	Distribution Revenue at Proposed Rates	$120,304,162			$114,562,987	
	Other Revenue:					
	Specific Service Charges	$2,621,919			$2,621,919	
	Late Payment Charges	$1,834,000			$1,834,000	
	Other Distribution Revenue	$954,255			$954,255	
	Other Income and Deductions	$1,157,873			$1,157,873	
	Operating Expenses:					
	OM+A Expenses	$43,713,000		($1,882,000)	$41,831,000	
	Depreciation/Amortization	$36,539,557		($296,874)	$36,242,684	
	Property taxes	$1,385,300		$ -	$1,385,300	
	Capital taxes	$1,321,920			$1,316,515	
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	($2,327,266)	**(3)**		($4,618,271)	
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$5,076,136			$3,894,082	
	Income taxes (grossed up)	$7,576,323			$5,812,063	
	Capital Taxes	$1,321,920			$1,316,515	
	Federal tax (%)	19.00%			19.00%	
	Provincial tax (%)	14.00%			14.00%	
	Income Tax Credits	$75,000			$152,000	
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	**(2)**		4.0%	**(2)**
	Common Equity Capitalization Ratio (%)	40.0%			40.0%	
	Prefered Shares Capitalization Ratio (%)					
	Cost of Capital					
	Long-term debt Cost Rate (%)	5.89%			5.89%	
	Short-term debt Cost Rate (%)	3.67%			1.33%	
	Common Equity Cost Rate (%)	8.40%			8.01%	
	Prefered Shares Cost Rate (%)					

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$921,136,105	($3,785,331)	$917,350,774
2	Accumulated Depreciation (average)	(3)	($462,085,096)	$1,820,985	($460,264,111)
3	Net Fixed Assets (average)	(3)	$459,051,009	($1,964,346)	$457,086,663
4	Allowance for Working Capital	(1)	$74,781,424	($5,053,916)	$69,727,507
5	**Total Rate Base**		$533,832,432	($7,018,262)	$526,814,170

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$45,098,300	($1,882,000)	$43,216,300
7	Cost of Power		$453,444,524	($31,810,775)	$421,633,749
8	Working Capital Base		$498,542,824	($33,692,775)	$464,850,049
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$74,781,424	($5,053,916)	$69,727,507

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$120,304,162	($5,741,175)	$114,562,987
2	Other Revenue	(1)	$6,568,047	$ -	$6,568,047
3	Total Operating Revenues		$126,872,209	($5,741,175)	$121,131,033
	Operating Expenses:				
4	OM+A Expenses		$43,713,000	($1,882,000)	$41,831,000
5	Depreciation/Amortization		$36,539,557	($296,874)	$36,242,684
6	Property taxes		$1,385,300	$ -	$1,385,300
7	Capital taxes		$1,321,920	($5,405)	$1,316,515
8	Other expense		$ -	$ -	$ -
9	Subtotal		$82,959,778	($2,184,279)	$80,775,499
10	Deemed Interest Expense		$18,399,338	($734,993)	$17,664,345
11	Total Expenses (lines 4 to 10)		$101,359,115	($2,919,272)	$98,439,843
12	**Utility income before income taxes**		$25,513,094	($2,821,904)	$22,691,190
13	Income taxes (grossed-up)		$7,576,323	($1,764,260)	$5,812,063
14	**Utility net income**		$17,936,771	($1,057,644)	$16,879,127

Notes

(1)

Other Revenues / Revenue Offsets			
Specific Service Charges	$2,621,919		$2,621,919
Late Payment Charges	$1,834,000		$1,834,000
Other Distribution Revenue	$954,255		$954,255
Other Income and Deductions	$1,157,873		$1,157,873
Total Revenue Offsets	$6,568,047		$6,568,047

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$17,936,770	$16,879,126
2	Adjustments required to arrive at taxable utility income	($2,327,266)	($4,618,271)
3	Taxable income	$15,609,504	$12,260,855
	Calculation of Utility income Taxes		
4	Income taxes	$5,076,136	$3,894,082
5	Capital taxes	$1,321,920	$1,316,515
6	Total taxes	$6,398,056	$5,210,597
7	Gross-up of Income Taxes	$2,500,187	$1,917,981
8	Grossed-up Income Taxes	$7,576,323	$5,812,063
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$8,898,243	$7,128,578
10	Other tax Credits	$75,000	$152,000
	Tax Rates		
11	Federal tax (%)	19.00%	19.00%
12	Provincial tax (%)	14.00%	14.00%
13	Total tax rate (%)	33.00%	33.00%

Notes

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$298,946,162	5.89%	$17,615,672
2	Short-term Debt	4.00%	$21,353,297	3.67%	$783,666
3	**Total Debt**	60.00%	$320,299,459	5.74%	$18,399,338
	Equity				
4	Common Equity	40.00%	$213,532,973	8.40%	$17,936,770
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$213,532,973	8.40%	$17,936,770
7	**Total**	100%	$533,832,432	6.81%	$36,336,107
	Per Board Decision				
		(%)	($)	(%)	
	Debt				
8	Long-term Debt	56.00%	$295,015,935	5.89%	$17,384,079
9	Short-term Debt	4.00%	$21,072,567	1.33%	$280,265
10	**Total Debt**	60.00%	$316,088,502	5.59%	$17,664,345
	Equity				
11	Common Equity	40.0%	$210,725,668	8.01%	$16,879,126
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$210,725,668	8.01%	$16,879,126
14	**Total**	100%	$526,814,170	6.56%	$34,543,471

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

Revenue Sufficiency/Deficiency

		Per Application		Per Board Decision	
Line No.	Particulars	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$9,181,607		$3,670,283
2	Distribution Revenue	$111,346,434	$111,122,555	$111,346,434	$110,892,704
3	Other Operating Revenue Offsets - net	$6,568,047	$6,568,047	$6,568,047	$6,568,047
4	**Total Revenue**	$117,914,481	$126,872,209	$117,914,481	$121,131,033
5	Operating Expenses	$82,959,778	$82,959,778	$80,775,499	$80,775,499
6	Deemed Interest Expense	$18,399,338	$18,399,338	$17,664,345	$17,664,345
	Total Cost and Expenses	$101,359,115	$101,359,115	$98,439,843	$98,439,843
7	**Utility Income Before Income Taxes**	$16,555,366	$25,513,094	$19,474,638	$22,691,190
8	Tax Adjustments to Accounting Income per 2009 PILs	($2,327,266)	($2,327,266)	($4,618,271)	($4,618,271)
9	**Taxable Income**	$14,228,100	$23,185,828	$14,856,367	$18,072,919
10	Income Tax Rate	33.00%	33.00%	33.00%	33.00%
11	**Income Tax on Taxable Income**	$4,695,273	$7,651,323	$4,902,601	$5,964,063
12	**Income Tax Credits**	$75,000	$75,000	$152,000	$152,000
13	**Utility Net Income**	$11,785,093	$17,936,771	$14,420,037	$16,879,127
14	**Utility Rate Base**	$533,832,432	$533,832,432	$526,814,170	$526,814,170
	Deemed Equity Portion of Rate Base	$213,532,973	$213,532,973	$210,725,668	$210,725,668
15	Income/Equity Rate Base (%)	5.52%	8.40%	6.84%	8.01%
16	Target Return - Equity on Rate Base	8.40%	8.40%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-2.88%	0.00%	-1.17%	0.00%
17	Indicated Rate of Return	5.65%	6.81%	6.09%	6.56%
18	Requested Rate of Return on Rate Base	6.81%	6.81%	6.56%	6.56%
19	Sufficiency/Deficiency in Rate of Return	-1.15%	0.00%	-0.47%	0.00%
20	Target Return on Equity	$17,936,770	$17,936,770	$16,879,126	$16,879,126
21	Revenue Sufficiency/Deficiency	$6,151,677	$1	$2,459,089	$1
22	**Gross Revenue Sufficiency/Deficiency**	$9,181,607 **(1)**		$3,670,283 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

(2) PowerStream shows revenue deficiency as difference between Total revenue at proposed rates and Total revenue at Rates (line 4).This model calculates revenue deficiency at "target income" level. Since Powerstream used a tax model to calculate the taxes at "current rates", the revenue deficiency (line 22) is slightly higher than the amount in the settlement.

REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

		Revenue Requirement	
Line No.	**Particulars**	**Application**	**Per Board Decision**
1	OM&A Expenses	$43,713,000	$41,831,000
2	Amortization/Depreciation	$36,539,557	$36,242,684
3	Property Taxes	$1,385,300	$1,385,300
4	Capital Taxes	$1,321,920	$1,316,515
5	Income Taxes (Grossed up)	$7,576,323	$5,812,063
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$18,399,338	$17,664,345
	Return on Deemed Equity	$17,936,770	$16,879,126
8	Distribution Revenue Requirement before Revenues	$126,872,208	$121,131,032
9	Distribution revenue	$120,304,162	$114,562,987
10	Other revenue	$6,568,047	$6,568,047
11	**Total revenue**	$126,872,209	$121,131,033
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1 **(1)**	$1 **(1)**

Notes

(1) Line 11 - Line 8

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REVENUE REQUIREMENT WORK FORM

Name of LDC: PowerStream
File Number: EB-2008-0244
Rate Year: 2009

Selected Delivery Charge and Bill Impacts
Per Draft Rate Order

		Monthly Delivery Charge				Total Bill			
			Per Draft	Change			Per Draft	Change	
		Current	Rate Order	$	%	Current	Rate Order	$	%
Residential	**1000** kWh/month	$ 33.79	$ 32.61	-$ 1.18	-3.5%	$ 114.14	$ 112.65	-$ 1.49	-1.3%
GS < 50kW	**2000** kWh/month	$ 66.19	$ 62.84	-$ 3.35	-5.1%	$ 234.85	$ 230.83	-$ 4.02	-1.7%

Notes:

Foregone Distribution Revenue and Rate Rider Calculation (for September 1st 2009 implementation)

	Billing determinants - May-Aug 2009			Current rates		Approved Rates	
	Customer count	kWhs	KWs	(Net of Smart Meter Adder)	Variable (excluding LV)	Fixed (Net of Smart Meter Adder)	Variable (excluding LV)
Residential	872,629	708,635,508	-	$ 12.02	$ 0.0129	$ 11.85	0.0134
GS<50	94,800	279,743,323	-	$ 28.70	$ 0.0112	$ 28.29	0.0115
GS>50	15,611	1,361,607,804	3,556,162	$ 301.73	$ 2.2713	$ 83.41	3.4606
Large Use	4	10,942,341	28,844	$ 8,978.09	$ 1.1989	$ 2,146.94	1.0355
USL	8,482	2,854,524	-	$ 14.35	$ 0.0111	$ 14.14	0.0086
Sentinel Lighting	568	237,877	609	$ 2.01	$ 6.0151	$ 1.98	9.2764
Street Lighting	255,219	14,748,372	44,126	$ 0.84	$ 3.3980	$ 0.83	4.8019
Total	**1,247,313**	**2,378,769,749**	**3,629,741**				

	Revenue at Current Rates May - August 2009			Revenue at approved rates May - August 2009			Foregone Distribution revenue May - August 2009		
	Fixed	Variable	Total	Fixed	Variable	Total	Fixed	Variable	Total
Residential	$ 10,489,001	$ 9,141,398	$ 19,630,399	$ 10,340,654	$ 9,495,716	$ 19,836,370	$ (148,347)	$ 354,318	$ 205,971
GS<50	$ 2,720,770	$ 3,133,125	$ 5,853,895	$ 2,681,901	$ 3,217,048	$ 5,898,950	$ (38,868)	$ 83,923	$ 45,055
GS>50	$ 4,710,257	$ 8,077,111	$ 12,787,367	$ 1,302,100	$ 12,306,454	$ 13,608,554	$ (3,408,157)	$ 4,229,343	$ 821,186
Large Use	$ 35,912	$ 34,581	$ 70,493	$ 8,588	$ 29,868	$ 38,455	$ (27,325)	$ (4,713)	$ (32,038)
USL	$ 121,717	$ 31,685	$ 153,402	$ 119,935	$ 24,549	$ 144,484	$ (1,781)	$ (7,136)	$ (8,918)
Sentinel Lighting	$ 1,142	$ 3,666	$ 4,807	$ 1,125	$ 5,653	$ 6,778	$ (17)	$ 1,987	$ 1,970
Street Lighting	$ 214,384	$ 149,940	$ 364,324	$ 211,832	$ 211,888	$ 423,720	$ (2,552)	$ 61,948	$ 59,396
Total	**$ 18,293,182**	**$ 20,571,505**	**$ 38,864,687**	**$ 14,666,135**	**$ 25,291,176**	**$ 39,957,311**	**$ (3,627,047)**	**$ 4,719,670**	**$ 1,092,623**

Notes

Customer count is the total of the number of customers for four months: May - August 2009

	Billing determinants - 8 months 2009			Foregone Revenue Rate Rider ($ per kWh /$ per kW)	
	Average Monthly Customer count	Total kWhs	Total KWs	Distribution Revenue to be recovered	Rate Rider (Sunset date: April 30, 2010)
Residential	218,157	1,325,815,139	-	$ 205,971	**$ 0.0002**
GS<50	23,700	523,383,217	-	$ 45,055	**$ 0.0001**
GS>50	3,903	2,547,487,700	6,633,568	$ 821,186	**$ 0.1238**
Large Use	1	20,472,473	53,965	$ (32,038)	**$ (0.5937)**
USL	2,121	5,340,645	-	$ (8,918)	**$ (0.0017)**
Sentinel Lighting	142	445,054	1,140	$ 1,970	**$ 1.7282**
Street Lighting	63,805	27,593,333	82,557	$ 59,396	**$ 0.7195**
Total	**311,828**	**4,450,537,560**	**6,771,230**	**$ 1,092,623**	

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POWERSTREAM - 2009 Rate Application

Rates Design - Validation

	Proceeds from distribution rates					Revenue requirements				Validation			
Customer Class	Fixed rate (w/o SM adder)	Volume	Variable rate	volume	Total proceeds	Distribution revenue	Low voltage charges	Transf. allowance recoveries	Total	Difference	Revenue re-allocation	Other difference	Due to rounding
Residential	$ 11.85	218,157	$ 0.0135	2,034,450,648	$ 58,487,047.12	$ 58,226,202	271,286	$ -	$ 58,497,488	(10,440)	-	(10,440)	**YES**
GS Less Than 50 kW	$ 28.29	23,700	$ 0.0116	803,126,540	$ 17,361,972.15	$ 17,288,227	97,781	$ -	$ 17,386,008	(24,036)	-	(24,036)	**YES**
GS 50 to 4,999 kW	$ 83.41	3,902	$ 3.5078	10,160,712	$ 39,547,378.56	$ 37,292,703	481,320	$ 1,779,742	$ 39,553,765	(6,387)	-	(6,387)	**YES**
GS 50 to 4,999 kW TOU	$ -	-	$ -	29,018	$ -	$ -	-	$ -	$ -	-	-	-	
Large Use	$ 2,146.94	1	$ 1.0913	82,809	$ 116,132.41	$ 205,714	4,623	$ 49,685	$ 260,022	(143,890)	(143,884)	(6)	**YES**
USL	$ 14.14	2,121	$ 0.0087	8,195,169	$ 431,104.41	$ 458,552	1,093	$ -	$ 459,645	(28,540)	(27,940)	(600)	**YES**
Sentinel Lighting	$ 1.98	142	$ 9.3165	1,750	$ 19,673.29	$ 11,603	70	$ -	$ 11,673	8,000	8,000	0	**YES**
Street Lighting	$ 0.83	63,805	$ 4.8386	126,683	$ 1,248,462.04	$ 1,079,985	4,653	$ -	$ 1,084,638	163,824	163,824	(0)	**YES**
Total					**$ 117,211,769.98**	**$ 114,562,987**	**$ 860,825**	**$ 1,829,428**	**$ 117,253,239**	**(41,469)**	**0**	**(41,469)**	

LRAM/SSM Recovery

			Per Settlement		Adjusted to Sep 1st implementation date	
Customer Class	LRAM/SSM Total	Billing determinant	Billing Units (2009)	Rate Rider	Billing Units (8 months)	Rate Rider
Residential	$ 190,316	*kWhs*	2,034,450,648	$0.0001	1,325,815,139	**$ 0.0001**
GS<50 kWs	$ 32,686	*kWhs*	803,126,540	$0.0000	523,383,217	**$ 0.0001**
GS>50 kWs	$ 292,320	*kWs*	10,189,730	$0.0287	6,633,568	**$ 0.0441**
Large Use	$ -	*kWs*	82,809	$0.0000	53,965	**$ -**
TOTALS	**$ 515,322**		**2,847,849,727**			

Regulatory Asset/Liabilities Recovery

Customer Class	Balance to be refunded	As per Settlement Proposal			Adjusted to Sep 1st implementation date			
		billing determinant	billing quantity	Rate Rider (over 24 months)	8 months	12 months	Total Billing quantity (20 months)	Rate Rider (over 20 months)
	$							
Residential	-$7,781,013	*kWhs*	2,034,450,648	$ (0.0019)	1,325,815,139	2,034,450,648	3,360,265,787	$ (0.0023)
GS<50	-$3,131,270	*kWhs*	803,126,540	$ (0.0019)	523,383,217	803,126,540	1,326,509,757	$ (0.0024)
GS>50	-$16,775,113	*kWs*	10,189,730	$ (0.8231)	6,633,568	10,189,730	16,823,298	$ (0.9971)
Time of use	$0	*kWs*	-		-	-	-	
Large Use	-$236,189	*kWs*	82,809	$ (1.4261)		*Note 1*		
USL	$16,805	*kWhs*	8,195,169	$ 0.0010	5,340,645	8,195,169	13,535,814	$ 0.0012
Sentinel Lighting	-$8,093	*kWs*	1,750	$ (2.3126)	1,140	1,750	2,890	$ (2.8005)
Street Lighting	-$174,025	*kWs*	126,683	$ (0.6869)	82,557	126,683	209,240	$ (0.8317)
Total	**-$28,088,899**							

Notes

1. To avoid negative distribution rates in the Large Use class, PowerStream will refund the amount of $236,189 as a separate fixed credit to the monthly bill over the recovery period. There is a single customer in the Large Use class and this amount is attributable to that customer. Based on a 24 month repayment period, PowerStream will credit this customer monthly for $9.841.21 until the entire amount of $236,189 is repaid. Based on an September 1, 2009 implementation date and 20 months recovery period, this monthly credit becomes $11,809.45

Rate Rider to Recover Smart Meter Costs

Revenue Requirement 2006	$	4,864
Revenue Requirement 2007	$	1,008,622
Revenue Requirement 2008	$	1,608,180
Revenue Requirement Total	$	2,621,665
Smart Meter Rate Adder	-$	2,002,866
Carrying Cost	-$	47,313
Smart Meter True-up	$	571,486
Metered Customers		249,355
Rate Rider to Recover Smart Meter Costs	**$**	**0.19**

2009 Addition to Rate Base

Fixed Assets		
Smart Meters	$	9,631,705
Computer Software	$	490,200
	$	10,121,905
Accumulated Depreciation		
Smart Meters	-$	967,351
Computer Software	-$	245,100
	-$	1,212,451
Addition to Net Fixed Assets - Jan. 1, 2009	**$**	**8,909,454**
2009 Amortization Expense		
Smart Meters	$	642,114
Computer Software	$	163,400
	$	805,514

Incremental Revenue Requirement Calculation

	2006		2007		2008		2009	
Net Fixed Assets		$ 30,306		$ 4,887,790		$ 9,312,211		$ 8,506,698
OM&A	$ -		$ 190,519		$ -		$ -	
WCA	15%	$ -	15%	$ 28,578	15%	$ -	15%	$ -
Rate Base		$ 30,306		$ 4,916,368		$ 9,312,211		$ 8,506,698
Deemed ST Debt	0%	$ -	0%	$ -	0%	$ -	0%	$ -
Deemed LT Debt	60%	$ 18,184	60%	$ 2,949,821	60%	$ 5,587,327	60%	$ 5,104,019
Deemed Equity	40%	$ 12,122	40%	$ 1,966,547	40%	$ 3,724,884	40%	$ 3,402,679
ST Interest	0.00%	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -
LT Interest	6.16%	$ 1,120	6.16%	$ 181,709	6.16%	$ 344,179	6.16%	$ 314,408
ROE	9.00%	$ 1,091	9.00%	$ 176,989	9.00%	$ 335,240	9.00%	$ 306,241
		$ 2,211		$ 358,698		$ 679,419		$ 620,649
OM&A		**$ -**		**$ 190,519**		**$ -**		**$ -**
Amortization		$ 2,090		$ 404,847		$ 805,514		$ 805,514
Grossed-up PILs		$ 562		$ 54,558		$ 123,247		$ 187,291
Revenue Requirement		$ 4,864		$ 1,008,622		$ 1,608,180		$ 1,613,454

PILs Calculation

	2006 Forecasted	2007 Forecasted	2008 Forecasted	2009 Forecasted
INCOME TAX				
Net Income	$ 1,091	$ 176,989	$ 335,240	$ 306,241
Amortization	$ 2,090	$ 404,847	$ 805,514	$ 805,514
CCA	-$ 2,508	-$ 522,381	-$ 934,797	-$ 768,144
Change in taxable income	$ 673	$ 59,456	$ 205,956	$ 343,611
Tax Rate	36.12%	36.12%	33.50%	33.00%
Income Taxes Payable	$ 243	$ 21,475	$ 68,995	$ 113,392
ONTARIO CAPITAL TAX				
Closing Net Fixed Assets	$ 60,612	$ 9,306,468	$ 8,664,354	$ 8,022,241
Less: Exemption	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ 60,612	$ 9,306,468	$ 8,664,354	$ 8,022,241
Ontario Capital Tax Rate	0.300%	0.225%	0.225%	0.225%
Net Amount (Taxable Capital x Rate)	$ 181.84	$ 20,939.55	$ 19,494.80	$ 18,050.04

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ 243.09	$ 21,475.33	$ 68,995.37	$ 113,391.69
Change in OCT	$ 181.84	$ 20,939.55	$ 19,494.80	$ 18,050.04
PIL's	$ 424.92	$ 42,414.88	$ 88,490.16	$ 131,441.73
	Gross Up	Gross Up	Gross Up	Gross Up
	33.00%	32.00%	30.50%	30.50%
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ 380.54	$ 33,618.24	$ 103,752.43	$ 169,241.33
Change in OCT	$ 181.84	$ 20,939.55	$ 19,494.80	$ 18,050.04
PIL's	**$ 562.37**	**$ 54,557.79**	**$ 123,247.23**	**$ 187,291.37**

Average Net Fixed Assets

Net Fixed Assets

		2006 Forecasted	2007 Forecasted	2008 Forecasted	2009 Forecasted
Opening Capital Investment		$ -	$ 62,702	$ 9,631,705	$ 9,631,705
Capital Investment		$ 62,702	$ 9,569,003		
Closing Capital Investment		$ 62,702	$ 9,631,705	$ 9,631,705	$ 9,631,705
Opening Accumulated Amortization		$ -	$ 2,090	$ 325,237	$ 967,351
Amortization Year One	15 years	$ 2,090	$ 318,967	$ -	$ -
Amortization Thereafter		$ -	$ 4,180	$ 642,114	$ 642,114
Closing Accumulated Amortization		$ 2,090	$ 325,237	$ 967,351	$ 1,609,464
Opening Net Fixed Assets		$ -	$ 60,612	$ 9,306,468	$ 8,664,354
Closing Net Fixed Assets		$ 60,612	$ 9,306,468	$ 8,664,354	$ 8,022,241
Average Net Fixed Assets		$ 30,306	$ 4,683,540	$ 8,985,411	$ 8,343,298

Net Fixed Assets

		2006 Forecasted	2007 Forecasted	2008 Forecasted	2009 Forecasted
Opening Capital Investment		$ -	$ -	$ 490,200	$ 490,200
Capital Investment		$ -	$ 490,200		
Closing Capital Investment		$ -	$ 490,200	$ 490,200	$ 490,200
Opening Accumulated Amortization		$ -	$ -	$ 81,700	$ 245,100
Amortization Year One	3 years	$ -	$ 81,700	$ -	$ -
Amortization Thereafter		$ -	$ -	$ 163,400	$ 163,400
Closing Accumulated Amortization		$ -	$ 81,700	$ 245,100	$ 408,500
Opening Net Fixed Assets		$ -	$ -	$ 408,500	$ 245,100
Closing Net Fixed Assets		$ -	$ 408,500	$ 245,100	$ 81,700
Average Net Fixed Assets		$ -	$ 204,250	$ 326,800	$ 163,400

For PILs Calculation

UCC

		2006 Forecasted	2007 Forecasted	2008 Forecasted	2009 Forecasted
Opening UCC		$ -	$ 60,194	$ 9,241,621	$ 8,502,292
Capital Additions		$ 62,702	$ 9,569,003	$ -	$ -
UCC Before Half Year Rule		$ 62,702	$ 9,629,197	$ 9,241,621	$ 8,502,292
Half Year Rule (1/2 Additions - Disposals)		$ 31,351	$ 4,784,502	$ -	$ -
Reduced UCC		$ 31,351	$ 4,844,695	$ 9,241,621	$ 8,502,292
CCA Rate Class	47				
CCA Rate	8%				
CCA		$ 2,508	$ 387,576	$ 739,330	$ 680,183
Closing UCC		$ 60,194	$ 9,241,621	$ 8,502,292	$ 7,822,108

UCC

		2006 Forecasted	2007 Forecasted	2008 Forecasted	2009 Forecasted
Opening UCC		$ -	$ -	$ 355,395	$ 159,928
Capital Additions		$ -	$ 490,200	$ -	$ -
UCC Before Half Year Rule		$ -	$ 490,200	$ 355,395	$ 159,928
Half Year Rule (1/2 Additions - Disposals)		$ -	$ 245,100	$ -	$ -
Reduced UCC		$ -	$ 245,100	$ 355,395	$ 159,928
CCA Rate Class	50				
CCA Rate	55%				
CCA		$ -	$ 134,805	$ 195,467	$ 87,960
Closing UCC		$ -	$ 355,395	$ 159,928	$ 71,967

Table Staff 16-1: Account 1555 Smart Meter Capital and Offset Account – Principal

Month	Opening Balance	SM Adder	Revenue Requirement	Closing Balance (excluding Stranded)
May-06	$ -	-$ 53,082	$ -	-$ 53,082
Jun-06	-$ 53,082	-$ 55,204	$ -	-$ 108,286
Jul-06	-$ 108,286	-$ 58,518	$ -	-$ 166,804
Aug-06	-$ 166,804	-$ 61,423	$ -	-$ 228,227
Sep-06	-$ 228,227	-$ 59,434	$ -	-$ 287,661
Oct-06	-$ 287,661	-$ 60,877	$ -	-$ 348,538
Nov-06	-$ 348,538	-$ 62,646	$ -	-$ 411,184
Dec-06	-$ 411,184	-$ 61,058	$ 4,864	-$ 467,378
Jan-07	-$ 467,378	-$ 62,549	$ -	-$ 529,927
Feb-07	-$ 529,927	-$ 57,342	$ -	-$ 587,269
Mar-07	-$ 587,269	-$ 63,206	$ -	-$ 650,475
Apr-07	-$ 650,475	-$ 59,797	$ 949	-$ 709,324
May-07	-$ 709,324	-$ 152,613	$ 148,030	-$ 713,907
Jun-07	-$ 713,907	-$ 161,831	$ 132,751	-$ 742,987
Jul-07	-$ 742,987	-$ 173,477	$ 141,482	-$ 774,982
Aug-07	-$ 774,982	-$ 167,808	$ 207,207	-$ 735,583
Sep-07	-$ 735,583	-$ 156,656	$ 216,486	-$ 675,754
Oct-07	-$ 675,754	-$ 188,831	$ 97,446	-$ 767,139
Nov-07	-$ 767,139	-$ 119,756	$ 59,303	-$ 827,592
Dec-07	-$ 827,592	-$ 166,758	$ 4,969	-$ 989,381
Jan-08	-$ 989,381	$ -	$ 134,015	-$ 855,366
Feb-08	-$ 855,366	$ -	$ 134,015	-$ 721,351
Mar-08	-$ 721,351	$ -	$ 134,015	-$ 587,336
Apr-08	-$ 587,336	$ -	$ 134,015	-$ 453,321
May-08	-$ 453,321	$ -	$ 134,015	-$ 319,306
Jun-08	-$ 319,306	$ -	$ 134,015	-$ 185,291
Jul-08	-$ 185,291	$ -	$ 134,015	-$ 51,276
Aug-08	-$ 51,276	$ -	$ 134,015	$ 82,739
Sep-08	$ 82,739	$ -	$ 134,015	$ 216,754
Oct-08	$ 216,754	$ -	$ 134,015	$ 350,769
Nov-08	$ 350,769	$ -	$ 134,015	$ 484,784
Dec-08	$ 484,784	$ -	$ 134,015	$ 618,799
Jan-09	$ 618,799	$ -	$ -	$ 618,799
Feb-09	$ 618,799	$ -	$ -	$ 618,799
Mar-09	$ 618,799	$ -	$ -	$ 618,799
Apr-09	$ 618,799	$ -	$ -	$ 618,799
2006		-$ 472,242	$ 4,864	
2007		-$ 1,530,624	$ 1,008,622	
2008		$ -	$ 1,608,180	
		-$ 2,002,866	$ 2,621,665	

Table Staff 16-2: Account 1555 – Interest

Month	Opening Balance (excluding Stranded)	Days	Rate	Interest	To Date
May-06	$ -	31	4.1400%	$ -	$ -
Jun-06	-$ 53,082	30	4.1400%	-$ 181	-$ 181
Jul-06	-$ 108,286	31	4.5900%	-$ 422	-$ 603
Aug-06	-$ 166,804	31	4.5900%	-$ 650	-$ 1,253
Sep-06	-$ 228,227	30	4.5900%	-$ 861	-$ 2,114
Oct-06	-$ 287,661	31	4.5900%	-$ 1,121	-$ 3,235
Nov-06	-$ 348,538	30	4.5900%	-$ 1,315	-$ 4,550
Dec-06	-$ 411,184	31	4.5900%	-$ 1,603	-$ 6,153
Jan-07	-$ 467,378	31	4.5900%	-$ 1,822	-$ 7,975
Feb-07	-$ 529,927	28	4.5900%	-$ 1,866	-$ 9,841
Mar-07	-$ 587,269	31	4.5900%	-$ 2,289	-$ 12,131
Apr-07	-$ 650,475	30	4.5900%	-$ 2,454	-$ 14,585
May-07	-$ 709,324	31	4.5900%	-$ 2,765	-$ 17,350
Jun-07	-$ 713,907	30	4.5900%	-$ 2,693	-$ 20,043
Jul-07	-$ 742,987	31	4.5900%	-$ 2,896	-$ 22,939
Aug-07	-$ 774,982	31	4.5900%	-$ 3,021	-$ 25,961
Sep-07	-$ 735,583	30	4.5900%	-$ 2,775	-$ 28,736
Oct-07	-$ 675,754	31	5.1400%	-$ 2,950	-$ 31,686
Nov-07	-$ 767,139	30	5.1400%	-$ 3,241	-$ 34,927
Dec-07	-$ 827,592	31	5.1400%	-$ 3,613	-$ 38,539
Jan-08	-$ 989,381	31	5.1400%	-$ 4,307	-$ 42,847
Feb-08	-$ 855,366	29	5.1400%	-$ 3,484	-$ 46,330
Mar-08	-$ 721,351	31	5.1400%	-$ 3,140	-$ 49,471
Apr-08	-$ 587,336	30	4.0800%	-$ 1,964	-$ 51,435
May-08	-$ 453,321	31	4.0800%	-$ 1,567	-$ 53,002
Jun-08	-$ 319,306	30	4.0800%	-$ 1,068	-$ 54,069
Jul-08	-$ 185,291	31	3.3500%	-$ 526	-$ 54,595
Aug-08	-$ 51,276	31	3.3500%	-$ 145	-$ 54,741
Sep-08	$ 82,739	30	3.3500%	$ 227	-$ 54,513
Oct-08	$ 216,754	31	3.3500%	$ 615	-$ 53,898
Nov-08	$ 350,769	30	3.3500%	$ 963	-$ 52,935
Dec-08	$ 484,784	31	3.3500%	$ 1,376	-$ 51,560
Jan-09	$ 618,799	31	2.4500%	$ 1,288	-$ 50,272
Feb-09	$ 618,799	28	2.4500%	$ 1,163	-$ 49,109
Mar-09	$ 618,799	31	2.4500%	$ 1,288	-$ 47,821
Apr-09	$ 618,799	30	1.0000%	$ 509	-$ 47,313

Settlement Proposal

May 29, 2009

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I. INTRODUCTION

This Settlement Proposal is filed with the Ontario Energy Board (the "OEB" or "Board") in connection with the Application of PowerStream Inc. ("PowerStream") for an order or orders approving or fixing just and reasonable rates, effective May 1, 2009, for distribution service and, in particular, the specific relief that PowerStream requested in Exhibit A1-2-2.

II. SETTLEMENT CONFERENCE

A Settlement Conference was held in one of the Board's hearing rooms on May 19-21, 2009 and on May 21, 22 and 25, 2009 via telephone conference call, in accordance with Rule 31 of the Board's *Rules of Practice and Procedure* and the Board's *Settlement Conference Guidelines.* This Settlement Proposal arises from the Settlement Conference.

PowerStream, the following intervenors and the Board's technical staff ("Board Staff") participated in all or a portion of the Settlement Conference:

- Consumers Council of Canada ("CCC");
- Energy Probe Research Foundation ("Energy Probe");
- School Energy Coalition ("SEC");
- Smart Sub-Metering Working Group ("SSMWG"); and
- Vulnerable Energy Consumers Coalition ("VECC").

All parties, except SSMWG, participated in the negotiation of the issues from May 19 to -21, 2009. Separate negotiations between PowerStream and SSMWG were held via telephone conference calls on May 21, 22 and 25, 2009. The Association of Major Power Consumers in Ontario ("AMPCO") and Hydro One Networks Inc. ("Hydro One") are intervenors; neither participated in the Settlement Conference and are not parties to the Settlement Proposal. Accordingly, the “parties” to this Settlement Proposal are PowerStream, CCC, Energy Probe, SEC, SSMWG and VECC.

III. ISSUES

The Settlement Proposal deals with all of the issues listed in Appendix "B" to the Board's Procedural Order No. 2 dated March 13, 2009 (the "Issues List"). A copy of the Issues List is provided in Schedule A.

IV. SETTLEMENT CATEGORIES

Each issue dealt with in this Settlement Proposal has been completely settled subject to the resolution by the Board of the suite metering issue, discussed below in Section VII. With this exception, there are no partially settled or unsettled issues.

V. PARAMETERS OF SETTLEMENT PROPOSAL

The Settlement Proposal has been prepared by PowerStream in consultation with CCC, Energy Probe, SEC, SSMWG and VECC in accordance with Rule 32 of the Board's *Rules of Practice and Procedure* and the Board's *Settlement Conference Guidelines*. Board Staff also participated in the Settlement Conference, as contemplated by the Board's *Settlement Conference Guidelines* (p. 5), but Board Staff is not a party to this Settlement Proposal. PowerStream and the parties nevertheless consulted with Board Staff during the preparation of this Settlement Proposal.

The Settlement Proposal describes the agreements reached on the issues. The description of each issue assumes that all of the parties participated in the negotiation of the issue.

The Settlement Proposal provides a direct link between each settled issue and the supporting evidence in the record to date. There are Schedules to the Agreement which provide further support. The intervenors agree that the Schedules were prepared by Powerstream, based on calculations and data that have not been the subject of any external review or testing, and those Schedules form part of and are an essential component of this Settlement Proposal. The parties have relied on the accuracy of the Schedules in agreeing to the settlement of the issues set forth herein.

The parties are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to each such issue.

According to the *Settlement Conference Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. PowerStream and the other parties consider that no settled issue, except for Issue 6.1 (Cost of Capital/Debt), requires a specific adjustment mechanism. The settlement of Issue 6.1 references the proposed adjustment mechanism. In addition, the settlement on each of the issues is subject to adjustment for the impacts of the Board’s determination on the suite metering issue, described below in Section VII.

The parties have settled the issues as a package and none of the parts of this Settlement Proposal is severable. If the Board does not accept the Settlement Proposal, in its entirety, then there is no Settlement Proposal (unless the parties agree that any part(s) of the Settlement Proposal that the Board does accept may continue as a valid Settlement Proposal without inclusion of any part(s) that the Board does not accept).

None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 32.05 of the Board's *Rules of Practice and Procedure*. Unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of the parties to raise the same issue in future proceedings before the Board whether or not PowerStream is a party to any such proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines.* The parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

VI. OVERVIEW OF SETTLEMENT PROPOSAL

Subject to the issue of suite metering, described below in Section VII, the parties achieved a comprehensive and complete settlement of all 37 issues on the Issues List.

The agreement among the parties reduces PowerStream's applied-for revenue requirement by $5.7 million, from $120.3 million to $114.6 million. This, in turn, reduces PowerStream's revenue deficiency from $8.9 million to $3.2 million.

Table 2 below, presents the components of PowerStream's revenue deficiency for the Test Year, on an applied-for and a settled basis.

Table 2: 2009 Revenue Deficiency

		Applied-for		**Settled**	
		%	**$000**	**%**	**$000**
1	Rate Base	--	533,832	--	526,814
2	Cost of Capital	6.81	---	6.56	--
3	Return on Rate Base **(A)**	---	36,336	--	34,543
4	Distribution Expenses	---	45,098	--	43,216
5	Amortization	---	36,540	--	36,243
6	Payment in Lieu of Taxes	---	8,898	--	7,129
7	**2009 Service Revenue Requirement (B)**	---	126,872	--	121,131
8	Less Revenue Offsets	---	(6,568)	--	(6,568)
9	**2009 Base Revenue Requirement (C)**	**---**	120,304	--	114,563
10	**Forecast 2009 Revenue at Current Rates**	---	111,346	--	111,346
11	2009 Revenue Deficiency	---	(8,958)	--	(3,217)

A= Line 1 X Line 2
B= Lines 3+4+5+6
C= Lines 7-8

Table 3, below, presents the underpinning causes of the revenue deficiency for the Test Year, on an applied-for and settled basis:

Table 3: Causes of Revenue Deficiency

Cause	Application (as filed on October 10, 2008) $000	Application (as updated on January 30,2009) $000	Settlement $000	Change (Settlement vs. January update) $000
Increase in Amortization Expense	(9,977)	(9,977)	(9,680)	297
Increase in Distribution Expenses	(6,815)	(6,815)	(4,933)	1,882
Increase in Return on Capital	(4,767)	(4,185)	(2,392)	1,793
Load Growth	10,517	9,096	9,094	(2)
Decrease in Payment in Lieu of Taxes	2,311	2,452	4,222	1,770
Increase in Revenue Offsets	471	471	471	0
Total 2009 Revenue Deficiency	**(8,261)**	**(8,958)**	**(3,217)**	**5,741**

Tables 4, 5 and 6, below, compare the monthly bill impacts, for a "typical" customer in each rate class, of PowerStream's as-filed revenue requirement (as *per* its January 30, 2009 update) with the revenue requirement negotiated pursuant to this Settlement Proposal. Table 4 compares the filed vs. negotiated impacts on total bill. Table 5 compares the impacts on the distribution portion of the bill. Table 6 compares the impact on the distribution portion of monthly customer bills, excluding the refund of regulatory liability amounts to customers. None of the percent changes that flow from this Settlement Proposal exceed the ten percent mitigation threshold on total bills specified in Section 13.1 of the 2006 EDR Handbook.

Table 4: Impacts on Total Bill for Typical Customer

			Typical Bill (as per Application)		Typical Bill (as per Settlement Proposal)	
Class	**Consumption per customer, kwh**	**Demand per customer, kw**	**$ Change**	**% Change**	**$ Change**	**% Change**
Residential	1,000	-	$(0.22)	-0.2%	$ (1.57)	-1.5%
GS<50	2,000	-	$(1.13)	-0.5%	$ (3.94)	-1.8%
GS>50	80,000	250	$(62.25)	-0.8%	$ (127.92)	-1.7%
Large Use	2,800,000	7,350	$(18,543.77)	-7.5%	$(18,136.07)	-7.3%
USL	500	-	2.30	3.9%	$ (1.10)	-1.9%
Sentinel Lighting	180	1	$0.20)	-1.1%	$ 0.44	2.4%
Street Lighting	882,119	2,639	$2,946.06	21.%	$ 1,152.63	0.8%

Table 5: Impact on the Distribution Portion of Bill for Typical Customer

			Typical Bill (as per Application)		Typical Bill (as per Settlement Proposal)	
Class	**Consumption per customer, kwh**	**Demand per customer, kw**	**$ Change**	**% Change**	**$ Change**	**%Change**
Residential	1,000	-	$(0.45)	-1.7%	$ (1.46)	-5.5%
GS<50	2,000	-	$(1.56)	-3.0%	$ (3.70)	-7.0%
GS>50	80,000	250	$(86.54)	-9.7%	$ (130.54)	-14.6%
Large Use	2,800,000	7,350	$(19,261.57)	-103.8%	$(18,873.28)	-101.7%
USL	500	-	2.05	10.2%	$ (1.06)	-5.3%
Sentinel Lighting	180	1	$0.22)	-4.4%	$ 0.43	8.5%
Street Lighting	882,119	2,639	$2,656.29	4.2.%	$ 1,164.81	1.9%

Table 6: Impact on the Distribution Portion of Bill for Typical Customer (Excluding Refund of Regulatory Liabilities)

Class	Consumption per customer, kwh	Demand per customer, kw	Typical Bill - Distribution charge	
			$ Change	% Change
Residential	1,000	-	$ 0.44	1.7%
GS<50	2,000	-	$ 0.10	0.2%
GS>50	80,000	250	$ 75.24	8.4%
Large Use	2,800,000	7,350	$ (8,391.45)	-45.2%
USL	500	-	$ (1.56)	-7.8%
Sentinel Lighting	180	1	$ 1.59	31.4%
Street Lighting	882,119	2,639	$ 2,977.69	4.7%

Tables 2 through 6 above have been prepared by Powerstream and have not been the subject of any review or testing. The intervenors have accepted these calculations, and relied on the correctness of these Tables in entering into this Agreement and recommending that the Board approve the settlement of issues as set forth herein.

VII. UNSETTLED SUB-ISSUE

Included in many of the general issues in this proceeding are impacts of PowerStream’s individual suite metering activities. SSMWG has taken the position that the revenue requirement impacts of those activities should not be included in rates in the Test Year. Powerstream believes that they should. Other parties have not, as yet, taken any position on this issue.

The parties agree that the evidence on this matter, and resulting submissions, should be put to the Board for a determination. In such hearing, it is agreed that all parties may participate, and the settlement by the parties of the issues as set forth in this Settlement Proposal shall have no effect on their ability to participate in that hearing, or on the positions they take on the suite metering issue or any part of it.

The costs associated with suite metering activities are included in rate base, OM&A, and potentially other consequential aspects of the calculation of revenue requirement, and the figures set forth in this Settlement Proposal include those amounts as filed by Powerstream. In the event that, after a hearing on this issue, the Board determines that all or any portion of those costs should not be included in revenue requirement, the amounts for each component of revenue requirement that may be affected will be adjusted to reflect the Board’s decision, and the lower adjusted figures shall be deemed to be the figures agreed to by the parties.

The settlement of all issues in this proceeding is therefore subject to any adjustments that arise from the Board’s decision on suite metering. Where, throughout this document, issues relating to revenue requirement and its components are listed as settled, the phrase “subject to the Board’s determination of the revenue requirement impacts of suite metering” shall be read in.

VIII. CONCLUSION

The parties are of the view that this Settlement Proposal will protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service, promote economic efficiency and cost effectiveness in the distribution of electricity, and maintain the financial viability of PowerStream. The parties believe that the distribution rates established in accordance with the terms and conditions of the Settlement Proposal are "just and reasonable" and will permit PowerStream to make the investments that are required in order to serve its customers, protect the integrity of its distribution system, maintain and improve the quality of its service and meet all compliance requirements in 2009.

IX. ISSUE-BY-ISSUE SETTLEMENTS

1. ADMINISTRATION (Exhibit A)

1.1 Has PowerStream responded appropriately to all relevant Board directions and settlement agreements from previous proceedings?

- **C*omplete Settlement*:** The parties accept the evidence of Powerstream that there are no outstanding PowerStream obligations arising from prior Board directives or from settlement agreements from previous proceedings.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibit, A1-31
  No IRs

1.2 Has PowerStream complied with the Board's Filing Requirements in filing all relevant information pertaining to this application?

- **C*omplete Settlement*:** The parties agree, for the purposes of obtaining settlement on all issues in this proceeding, that PowerStream has complied with the Board's Filing Requirements *vis-à-vis* its application for 2009 distribution rates.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits A1-1-1, A1-2-1, A1-2-2, A1-3-1, A1-4-1, A2-1-1. A2-1-2, A2-1-3, A2-2-1, A2-2-2, A2-3-1, A3-1-1
  Board Staff Interrogatories #1, 5, 35
  VECC Interrogatories #5, 6
  CCC Interrogatories #1, 2, 3, 4, 5, 6, 7, 19, 20, 37
  SEC Interrogatories #1, 2, 3, 4, 5, 6, 8, 9, 11, 12, 18, 20, 21, 22, 23

2. RATEBASE (Exhibit B)

2.1 Are the amounts proposed for Rate Base appropriate?

- ***Complete Settlement*:** In its application (as updated on January 30, 2009), PowerStream sought the Board's approval of a forecast rate base of $533,832,000 for the 2009 Test Year. This amount comprised $459,051,000 in respect of net fixed assets and $74,781,000 in respect of working capital allowance.

  The parties agree that the "net fixed assets" component of PowerStream's rate base forecast shall be: (i) decreased by $2,359,000 to reflect PowerStream's actual capital spending in 2008, relative to the amount that is embedded in PowerStream's 2009 forecast and the impact of that change on opening rate base; and (ii) increased by $395,000 to reflect a correction in the way in which the value of smart meter capital assets are calculated for rate base purposes (see Issue 8.7 and Schedule G).

  The parties also agree that the "working capital allowance" component of rate base shall be adjusted to reflect: (i) a decrease of $31,811,000 in the cost of power as per the Navigant Consulting April 2009 updated forecast; and (ii) a decrease of $1,882,000 ~~million~~ in distribution expenses, as per the settlement of Issue 4.1. These decreases result in a $5,054,000 reduction in PowerStream's working capital allowance (i.e., 15% of $33,693,000).

  The resultant forecast rate base for the Test Year is shown in Table 2.1 below.

Table 2.1: Rate Base ($000)

	As filed - Jan. 2009 Update	**Settlement Proposal**
Net Fixed Assets	459,051	457,087
Working Capital Allowance	74,781	69,727
Total	**533,832**	**526,814**

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits B1-1-1, B1-4-1, B1-4-2,B1-5-1,B1-5-2, B1-5-3, B1-7-1, B1-7-2
  Board Staff Interrogatories #11, 14
  VECC Interrogatories #7, 24, 25
  Energy Probe Interrogatories #2, 5, 6,
  CCC Interrogatories #8, 16, 17, 18
  SEC Interrogatory #17

2.2 Are the amounts proposed for 2009 Capital Expenditures appropriate?

- ***Complete Settlement*:** In its application (as updated on January 30, 2009), PowerStream's forecast capital expenditures of $85,241,000 for the 2009 Test Year, net of contributed capital. The parties accept, in the context of the Settlement Proposal, that rate base should be calculated for 2009 using this capital spending forecast.

Evidence: The evidence on this issue includes the following:

Exhibits B1-2-1, B1-4-1, B1-4-2, B1-5-1, B1-5-4, B1-6-1
Board Staff Interrogatories #2, 3, 4, 6, 7, 8, 9, 10, 12, 13
VECC Interrogatories #8, 9, 11, 14, 15, 16, 17, 18, 19, 20, 22, 23
Energy Probe Interrogatories #3, 4
CCC Interrogatories #6, 8, 9, 10, 11, 12, 13, 14, 16
SEC Interrogatory #14, 16

2.3 Has the Working Capital Allowance been determined appropriately?

- ***Complete Settlement*:** See Issue 2.1 above.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits B2-1-1, B2-1-2, B2-1-3
  Board Staff Interrogatory #19
  VECC Interrogatories #26, 27
  Energy Probe Interrogatories #7, 8
  CCC Interrogatory #21
  SEC Interrogatories #13, 18

2.4 Does the asset condition information and the Distribution System Planning Report adequately address the condition of the distribution system assets and support the planning and budgeting for OMA and Capital expenditures for 2009?

- ***Complete Settlement*:** The parties agree that the evidence on the record, to-date, adequately addresses the condition of the distribution system assets and supports the planning and budgeting for OM&A and capital expenditures in the 2009 Test Year.

- **Evidence: The evidence on this issue includes the following:**

Exhibits B1-2-1
VECC Interrogatory #10

2.5 Is PowerStream's Overhead Capitalization Policy appropriate?

- ***Complete Settlement*:** For the purpose of achieving settlement on all issues, the parties accept PowerStream's capitalization policy as described in Exhibit B1-3-1.

- **Evidence: The evidence on this issue includes the following:**

Exhibit B1-3-1
Board Staff Interrogatories #37, 42
VECC Interrogatories #12, 13
SEC Interrogatories #15, 24, 25(e), 27

3. REVENUE REQUIREMENT (Exhibit C)

3.1 Is the calculation of the proposed revenue requirement for 2009 appropriate?

- ***Complete Settlement*****:** In its application, PowerStream sought approval of a 2009 Base Revenue Requirement ("BRR") of $120,304,000, with a forecast 2009 revenue deficiency of $8,958,000. As a result of the settlement of Issues 2.1 (Rate Base), 4.1 (OM&A), 4.7 (PILs) and 6.1 (Cost of Capital/Debt)**,** the parties accept that the BRR shall be reduced to $114,563,00, with a forecast 2009 revenue deficiency of $3,217,000, subject to the adjustment mechanism described in the settlement of Issue 6.1.

  The parties are of the view that the adjusted BRR is sufficient to permit PowerStream to operate its distribution system in a safe and reliable manner, invest in capital and earn a fair return after recovery of all distribution operating expenditures.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits G1-1, G-1-2, I-6-6

3.2 Is the proposed amount for 2009 Other Revenues, including revenues from affiliates and related parties appropriate? Is the methodology used to cost and price these services appropriate?

- ***Complete Settlement*****:** In its application, PowerStream forecast that it would receive $6,568,047 of non-distribution ("Other Revenue" or "Revenue Offsets") in connection with "specific service charges," "late payment charges, "other distribution revenue" and "other income and deductions". The parties accept this amount for the purpose of setting 2009 rates.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits C2-1-1, C2-1-2, D1-1-6, D1-1-7, D1-1-8
  Board Staff Interrogatories #20, 21
  VECC Interrogatory #36
  Energy Probe Interrogatories #13, 14
  CCC Interrogatory #22
  SEC Interrogatory #19

3.3 Are the proposed Specific Service Charges for 2009 appropriate?

- ***Complete Settlement*:** In its 2006 EDR Application, PowerStream sought and received approval to use the default Specific Service Charges in the Board's *2006 Electricity Distribution Rate Handbook*. In its 2009 application, PowerStream did not propose any changes to these Specific Service Charges. The parties accept the evidence of Powerstream that these charges remain appropriate.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit C2-1-2

3.4 Are PowerStream's economic and business planning assumptions for 2009 appropriate?

- ***Complete Settlement*:** For the purpose of achieving settlement of all of the issues, the parties accept PowerStream's economic and business planning assumptions for 2009 as reasonable and appropriate .

- ***Evidence:*** The evidence on this issue includes the following:

Exhibits B1-2-1, D1-1-2, D1-1-2
Board Staff Interrogatory #40

3.5 Is the load forecast and methodology appropriate including the weather normalization methodology?

Complete Settlement**:** PowerStream's load forecast was developed using an econometric model. Due to the lack of historic data by customer class, PowerStream used aggregate data since 1998 and divided the forecast sales by customer class based on past patterns. Ontario GDP was determined to be the variable most correlated to energy sales. Region of York Planning Department reports were used for the customer forecasts. Weather normalization was done based on the 10 year Statistics Canada heating degree days and cooling degree days. CDM adjustments were made by applying OPA forecasts to PowerStream's service territory. The parties agree that the addition of more class specific consumption data would improve the load forecasting methodology .

Notwithstanding that the methodology may be improved in the future, the parties accept the current methodology and the resultant load forecast for the purpose of setting 2009 distribution rates.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibits C1-1-1, C1-1-2, C1-1-3, C1-14
Board Staff Interrogatories #22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32
VECC Interrogatories #3, 28, 29, 30, 31, 32, 33, 34, 35, 55
Energy Probe Interrogatories #9, 10, 11, 12

3.6 Has the impact of Conservation and Demand Management initiative been suitably reflected in the load forecast?

- ***Complete Settlement*****:** See the settlement of Issue 3.5
- ***Evidence:*** The evidence on this issue includes the following:

Exhibit C1-1-2
Board Staff Interrogatory #33

3.7 Is the Revenue Deficiency calculation for the test year appropriate? (Exhibit G)

- ***Complete Settlement*****:** See the settlement of Issue 3.1.
- ***Evidence:*** The evidence on this issue includes the following:

VECC Interrogatories #2, 4, 56
Energy Probe Interrogatory #1
SEC Interrogatory #7

4. COST OF SERVICE (Exhibit D)

4.1 Are the overall levels of the 2009 Operation, Maintenance and Administration budgets appropriate?

- ***Complete Settlement:*** In its application, which was filed in October 10, 2008, PowerStream sought approval of forecast Operation, Maintenance and Administration ("OM&A") expenses for the 2009 Test Year of $45,098,000. On January 1, 2009, PowerStream amalgamated with Barrie Hydro Distribution Inc. In its decision (EB-2008-0335) approving the amalgamation, the Board also approved a rate rebasing schedule, including PowerStream's proposal to seek revised 2009 distribution rates on a cost of service basis for the Powerstream distribution service area and excluding the Barrie Hydro service area. The application for 2009 does not include recognition of either the merger-related costs ($4,302,000) or savings ($1,882,000) that the amalgamated entity expects in 2009, nor any of the additional net savings that the amalgamated entity expects to achieve from the merger in subsequent years until its next rebasing. .

  The parties agreed to reduce PowerStream's forecast of 2009 OM&A expenses by an amount equal to the estimated 2009 cost savings resulting from the merger, but not to include in PowerStream’s forecast any of the incremental costs in 2009 of the merger, nor to include any provision in 2009 for future savings from the merger that may arise after 2009. The forecast 2009 OM&A spending of $45,098,000 is therefore reduced by $1,882,000, the full amount of the amalgamated entity’s 2009 merger savings, to $43,216,000.

  Subject to the $1,882,000 reduction, the parties accept PowerStream's 2009 OM&A forecast for the purpose of establishing 2009 revenue requirement.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits D1-1-1, D1-1-2, D1-1-3, A2-3-1
  Board Staff Interrogatories #34, 35, 36, 39, 41, 43, 44, 45, 46, 47
  VECC Interrogatories #37, 38, 39, 40
  Energy Probe Interrogatories #15, 16
  CCC Interrogatories #23, 24, 25, 26, 27, 28
  SEC Interrogatory #10, 25

4.2 Are the proposed Purchased Services and Shared Services amounts appropriate?

- ***Complete Settlement:*** For the purpose of achieving a settlement of all of the issues, the parties have accepted the evidence of PowerStream on this issue.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit D1-1-4
Board Staff Interrogatory #48
VECC Interrogatory #40
CCC Interrogatory #29
SEC Interrogatory #26

4.3 Are the methodologies used to cost and price services from affiliates and related parties appropriate? Are the Affiliate Service Agreements appropriate?

- ***Complete Settlement:*** For the purpose of achieving a settlement of all of the issues, the parties have accepted the evidence of PowerStream on this issue.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibits D1-1-6, D1-1-7, D1-1-8
Board Staff Interrogatory #49
Energy Probe Interrogatory #18
VECC Interrogatory #43
SEC Interrogatory #28, 29

4.4 Are the 2009 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate?

- ***Complete Settlement*:** For the purpose of achieving a settlement of all of the issues, the parties have accepted the evidence of PowerStream on this issue.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit D1-1-9
Board Staff Interrogatories #50, 51
VECC Interrogatory #44a
Energy Probe Interrogatory #19
CCC Interrogatories #30, 31
SEC Interrogatories #30, 31

4.5 Is PowerStream's depreciation expense appropriate?

- ***Complete Settlement***: See settlement of Issue 2.1. The effect of this settlement is to decrease depreciation expense from $36,540,000 to $36,243,000.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibit D1-1-5
  Board Staff Interrogatory #15
  VECC Interrogatory #42
  Energy Probe Interrogatories #8, 17
  SEC #27

4.6 Are the amounts proposed for 2009 capital and property taxes appropriate?

- ***Complete Settlement***: For the purpose of achieving a settlement of all of the issues, the parties have accepted the evidence of PowerStream on this issue.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits D1-1-3, D2-1-2, D2-1-2, D2-1-3
  Energy Probe Interrogatories #20, 21

4.7 Is the amount proposed for 2009 Payments in Lieu of Taxes, including the methodology, appropriate?

- ***Complete Settlement***: In its application, PowerStream sought approval to include in revenue requirement an amount of $8,898,000 in respect of Payments in Lieu of Taxes ("PILs"). This amount was calculated using Federal and Ontario income tax rates and Ontario capital tax rates that were current as of the date of filing (i.e., October 10, 2008).

  PowerStream has updated the PILs amount to reflect the new tax measures that were included in the 2009 Federal and Ontario Budgets. The calculation of the revised PILs amount is set out below in Table 4.7.

Table 4.7: Payments in Lieu of Taxes (PILs) $000

	As filed - Jan. 2009 Update	Settlement Proposal
Taxable Income	23,186	19,389
PILs	8,898	7,129

Please see Schedule B for complete details.

For the purpose of achieving a settlement of all of the issues, the parties have accepted the evidence of PowerStream on this issue.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits D2-1-2, D2-1-2, D2-1-3
  Board Staff Interrogatory #52
  VECC Interrogatory #45
  Energy Probe Interrogatories #22, 23

5. REGULATORY ASSETS (Exhibits E)

5.1 Is the proposal for the amounts, disposition and continuance of PowerStream's existing Deferral and Variance Accounts (Regulatory Assets) appropriate?

- ***Complete Settlement*:** PowerStream has updated the amounts for disposition and the rate riders to reflect responses to Board Staff Interrogatories. The amount to be returned to customers has been increased from $27,899,049 (as filed) to $28,088,900. This $189,851 increase reflects; (i) interest on account 2425 balances up to April 30, 2006; and (ii) adjustments to reflect actual interest rates from July 1, 2008 to April 30, 2009.

  Please see Schedule C for details.

  For the purpose of achieving a settlement of all of the issues, the parties have accepted the evidence of PowerStream on this issue.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits E1-1-1, E1-1-2
  Board Staff Interrogatories #53, 54, 55, 56, 57, 58, 67, 69
  VECC Interrogatory #46
  Energy Probe Interrogatories # 24, 25, 26

6. COST OF CAPITAL/DEBT (Exhibit F)

6.1 Is the proposed Capital Structure and Rate of Return on Equity for PowerStream's distribution business appropriate?

- ***Complete Settlement:*** For rate-making purposes, PowerStream's deemed capital structure and cost of capital were determined in accordance with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (*December 20, 2006*) (the "COC Report"). The COC Report continues the equity risk premium/formulaic approach to determining the rate of return on common equity, or "ROE," that the Board implemented for gas utilities in 1997.

  In its application, PowerStream calculated a 2009 rate of return on rate base using: (i) a deemed capital structure of 56 percent long-term debt, 4 percent short-term debt and 40 percent equity; (ii) a 5.89 percent cost of long-term debt and 3.67 percent cost of short-term debt; and (iii) an ROE of 8.4 percent. The rate of return on rate base for 2009 calculated in accordance with these values (which were current as of the date of filing), was 6.81 percent.

  By letter to all licensed electricity distributors, dated February 24, 2009, the Board updated the cost of capital parameter values for 2009.

  The parties accept PowerStream's deemed capital structure for the purpose of determining the rate of return on rate base for 2009. The parties agree that PowerStream's 2009 forecast weighted average cost of capital, as filed, should be revised to reflect the updated cost of capital parameter values set out in the Board's February 24th letter. The calculation of PowerStream's rate of return on rate base for 2009, in accordance with the updated parameters, is set out in Table 6.1 below.

Table 6.1: Weighted Average Cost of Capital

	Deemed Capital Structure	**Rate**	**Weighted Average Cost of Capital**
Long-term debt	56%	5.89%	3.30%
Short-term debt	4%	1.33%	0.05%
Equity	40%	8.01%	3.20%
Total	**100%**		**6.56%**

By letter dated March 16, 2009 to "All Interested Stakeholders," the Board initiated a consultative process (EB-2009-0084) to help it to determine whether current economic and financial market conditions warrant an adjustment to any of the cost of capital parameter values set out in the Board's letter of February 24, 2009. The parties agree that if the Board makes any such adjustment as a result of this consultation that is intended by the Board to apply to 2009 rates for parties whose cost of service applications have been the subject of a Board decision (whether based on a settlement or otherwise), PowerStream will adjust its cost of capital parameter values accordingly as directed in the Board's decision on that consultation.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits F1-1-1, F1-1-2
  Board Staff Interrogatory #59
  VECC Interrogatory #48a
  Energy Probe Interrogatories #27, 28

6.2 Are PowerStream's proposed costs and mix for its short and long-term debt for the 2009 test year appropriate?

- ***Complete Settlement*:** See settlement of Issue 6.1.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibits F1-1-1, F1-1-2
  Board Staff Interrogatory #59
  VECC Interrogatory #47
  SEC #32, 33, 34

7. COST ALLOCATION AND RATE DESIGN (Exhibit H)

7.1 Is PowerStream's cost allocation appropriate?

- ***Complete Settlement*:** PowerStream calculated 2009 revenue-to-cost ratios for each customer class on the basis of an updated cost allocation model (its "2009 Cost Allocation Model"). Some ratios were then adjusted to bring them within the "ranges of tolerance" established by the Board in its report on the *Application of Cost Allocation for Electricity Distributors (November 28, 2007)*. The resulting cost-to-revenue ratios were set out in Table 1 of Exhibit H-1-2 in PowerStream's application.

  As a result of the settlement of the series 2, 3, and 4 issues herein, PowerStream has further updated its 2009 Cost Allocation Model to reflect agreed-upon adjustments to rate-base, OM&A and, consequently, revenue requirement. The resultant revenue-to-cost ratios were then adjusted in order to bring them within the "ranges of tolerance" as follows:

  a. the "Large Use" rate class revenue-to-cost ratio was adjusted downwards to the top of its "range of tolerance" (i.e., to 115%);

  b. the "Unmetered Scattered Load" rate class revenue-to-cost ratio was adjusted downwards to the top of its "range of tolerance" (i.e., to 119%);

  c. the "Street Lighting" rate class revenue-to-cost ratio was adjusted upward to: (i) bring it within its range of tolerance; and (ii) absorb a portion of the reduction in the amount of revenue requirement allocated to the "Large Use" rate class; and

  d. the "Sentinel Lighting" rate class revenue-to-cost ratio was adjusted upwards to: (i) bring it within its range of tolerance; and (ii) absorb a portion of the reduction in the amount of revenue requirement allocated to the "Large Use" rate class.

  Table 7.1 below shows the adjustments made to reflect the provisions of this Settlement Proposal.

Table 7.1: Revenue-to-Cost Ratios

	As per Information filing PowerStream RUN 2	Test Year at calculated rates	OEB Proposed Range		Proposed per Settlement
	2006	2009	Low	High	2009
Revenue /Expenses Ratio					
Residential	93.4%	92.9%	85%	115%	**92.9%**
GS Less Than 50 kW	113.5%	116.7%	80%	120%	**116.7%**
GS 50 to 4,999 kW	108.1%	106.5%	80%	180%	**106.5%**
GS 50 to 4,999 kW Legacy					
Large Use	75.9%	378.8%	85%	115%	**115.0%**
Unmetered Scattered Load	169.6%	126.4%	80%	120%	**119.9%**
Sentinel Lighting	16.4%	45.5%	70%	120%	**75.4%**
Street Lighting	54.4%	64.8%	70%	120%	**74.5%**

In Table 7.1 above, the ratios in the column “Test Year at Calculated Rates” are the result of updating the 2009 Cost Allocation Model to reflect the changes in revenue requirement agreed upon in this Settlement Proposal. The ratios in the column “Proposed per Settlement” reflect the agreement among parties in respect of Large Use, Street Lighting and Sentinel Lighting customer classes, noted above. For the Unmetered Scattered Load customer class, the ratio was adjusted to bring it within the Board’s range. Please see Schedule D for details.

For the purpose of achieving settlement of all issues, the parties accept the use of PowerStream's cost allocation methodology for 2009 rates, and the resultant revenue-to-cost ratios, for each rate class, as revised to reflect this Settlement Proposal.

Evidence: The evidence on this issue includes the following:

Exhibits H-1-1, H-1-2, H-1-1
Board Staff Interrogatory #60
VECC Interrogatories #48B, 49, 50

7.2 Are the proposed revenue to cost ratios appropriate? (Exhibit I)

- ***Complete Settlement*:** See the settlement of Issue 7.1
- ***Evidence:*** The evidence on this issue includes the following:

Exhibits H-1-2, I-1-1, I-1-2, I-6-4
Board Staff Interrogatory #61
VECC Interrogatory # 51
SEC Interrogatories #35, 36

8. Rate Design (Exhibit I)

8.1 Are customer charges and the fixed-variable splits for each class appropriate?

Complete Settlement**:** VECC takes no position on this issue. All of the other parties agree that the customer charges and the fixed-variable splits that are set out in its application (as of January 30, 2009) are appropriate, subject to the following changes:

(i) the fixed charge applicable to the General Service > 50kW rate class is reduced from $301.73 to $83.41 so that it does not exceed the range stipulated in the Board's current guidelines; and

(ii) the fixed charge applicable to the "Large Use" rate class is reduced from $3,978.09 to $2,146.94 to be closer to the top of the range in the Board's current guidelines, but it is not reduced completely, in order to ensure that the variable charge, net of transformer credit, will be a positive amount.

The above-noted fixed charges do not include the Smart Meter rate adder.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit I-1-1, I-6-1, I-6-2
Board Staff Interrogatories #62, 63
SEC Interrogatories #37, 38

8.2 Are PowerStream's proposed rates appropriate?

- ***Complete Settlement*****:** Schedule E to this Settlement Proposal sets out PowerStream's proposed 2009 distribution rates, adjusted to reflect the provisions of the Settlement Proposal. The parties accept these rates as appropriate for the 2009 rate year.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit I-6-2

8.3 Are the customer bill impacts appropriate?

- ***Complete Settlement***: Schedule F to this Settlement Proposal sets out the monthly bill impacts associated with the recovery and allocation of PowerStream's applied-for revenue requirement, as adjusted to reflect the provisions of the Settlement Proposal. The parties accept, as appropriate for the 2009 rate year, these bill impacts.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit I-6-3, I-6-5, A1-4-1
VECC Interrogatory #1

8.4 Are the proposed Low Voltage and Retail Transmission Service Rates appropriate?

- ***Complete Settlement***: The parties accept, as appropriate, the Low Voltage and Retail Service Rates set out in PowerStream's application.

- ***Evidence:*** The evidence on this issue includes the following:

Exhibit I-4-1, I-5-1
Board Staff Interrogatory #64, 65, 66

8.5 Are the proposed Loss Factors appropriate?

- ***Complete Settlement:*** The parties accept PowerStream's proposed Loss Factor, recalculated to reflect the use of a three-year (2004-2006) average and ignoring the abnormally high year, 2007. The parties agree that the resultant Loss Factor – 2.99% (previously 3.33%) – is the appropriate billing determinant.

Table 8.5: Recalculation of Loss Factor

	2004	2005	2006
"Wholesale" kWh (IESO)	6,645,252,037	7,030,201,674	6,948,341,694
"Retail" kWh (Distributor)	6,431,131,687	6,832,435,064	6,744,270,701
Loss Factor	3.22%	2.81%	2.94%
		Average	**2.99%**

- ***Evidence:*** The evidence on this issue includes the following:

Exhibits D1-1-10, D1-1-11
Board Staff Interrogatory #68
VECC Interrogatory #44B

8.6 Are the proposed Regulatory Asset (Deferral and Variance Account) rate riders appropriate?

- ***Complete Settlement:*** PowerStream has recalculated the regulatory asset rate riders proposed in its application to reflect the Board's current "billing determinant" methodology. The revised rate riders are set out in Schedule C of this Settlement Proposal. The parties accept, as appropriate, the revised rate riders.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibit E1-1-1, E1-1-2, I-1-2

8.7 Is the Smart Meter rate adder change appropriate?

- **C*omplete Settlement*:** **The parties agree that the Smart Meter Actual Cost Recovery rate adder should be recalculated as shown below** in Table 8.7. No change is required in the calculation of Smart Meter Future Cost Recovery rate rider. Both riders have been calculated on the basis of a twelve month recovery period.

Table 8.7 Smart Meter Rate Adder

Monthly Rate Rider	Per Application	Settlement Proposal (Corrected)	Settlement Proposal (Original)
Future Cost Recovery	$ 1.04	$ 1.04	$ 1.04
Actual Cost Recovery	$ (0.19)	$ 0.19	$ 0.28
Total	**$ 0.85**	**$ 1.23**	**$ 1.32**

The Smart Meter Actual Cost Recovery rate rider has been updated to reflect the calculation made by Board Staff that was provided to the parties at the Settlement Conference. Board Staff’s calculation was reviewed by the parties at the Settlement Conference and found to be acceptable. Board Staff’s calculation is attached as Schedule G of this Settlement Proposal.

Board Staff’s calculation has taken the Actual Cost Recovery worksheet as filed by PowerStream and converted this to a multi-year revenue requirement calculation that properly reflects the timing of when the Smart Meter assets are being added to rate base and included in rates. The sheet originally filed by PowerStream in its Application was taken from Appendix E of the Smart Meter Combined Proceeding (EB-2007-0063). PowerStream did not calculate the revenue requirement on these assets for 2008 and the carrying costs for the period January 1, 2008 to April 30, 2009. The Board Staff calculation has included these items.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibit I-3-1, I-3-2, I-3-3

  Board Staff Interrogatories #16, 17, 18, 38, 70

  VECC Interrogatories #54, 55A

  CCC Interrogatories # 32, 33, 34

9. RATE IMPLEMENTATION

9.1 Is it appropriate to declare rates interim as of May 1, 2009?

- This issue is no longer outstanding. By order issued March 31, 2009, the Board made PowerStream's current rates interim, effective May 1, 2009 pending determination of its 2009 rates application and the issuance of a rate order reflecting such determination.

9.2 What is the appropriate effective date of the proposed rates? What mechanism (if any) should be used to recover any shortfall, or refund any over-collection, after May 1, 2009)?

- ***Complete Settlement*****:** In its application, PowerStream sought an order approving final rates for the 2009 rate year effective May 1, 2009. The parties accept this proposal. PowerStream proposes that the new rates which are effective May 1, 2009 be implemented August 1, 2009. Certain adjustments will be necessary to reflect the difference between the effective date and the implementation date.

  Fixed and variable distribution rates will be adjusted by a rate rider to reflect that the 2009 increase in rates will be collected over nine months, August 1, 2009 to April 30, 2010, rather than the full twelve month period.

  The LRAM and SSM rate riders would be adjusted to reflect that the amount to be recovered will be collected over nine months, August 1, 2009 to April 30, 2010, rather than the full twelve month period.

  Regulatory Asset Recovery rate riders would be recalculated for disposition over a twenty one month period, August 1, 2009 to April 30, 2011.

  The Smart Meter Actual Cost Recovery rate rider will be adjusted to reflect that the amount to be recovered will be collected over nine months, August 1, 2009 to April 30, 2010, rather than the full twelve month period.

  PowerStream does not propose to adjust the Smart Meter Future Cost Recovery rate rider, retail transmission rates, or the Rural Rate Protection Charge. These differences will be captured in variance and deferral accounts for future true up.

  PowerStream will provide supporting calculations for these adjustments and revised bill impacts with the Draft Rate Order.

10. OTHER ISSUES

10.1 Is the LRAM and SSM proposal appropriate? (Exhibit I)

- ***Complete Settlement:*** In its application, PowerStream sought recovery of a Lost Revenue Adjustment Mechanism or "LRAM" amount of $429,896 and a Shared Savings Mechanism or "SSM" amount of $398,214, calculated up to and including December 31, 2007. These amounts total to $828,110.

  The parties agree that the LRAM amount should be reduced from $429,896 to $300,088 to reflect the recalculation of the "kWh savings" for the Spring and Fall 2006 and 2007 "EKC CFL" programs using the 2007 Ontario Power Authority ("OPA") saving assumptions.

  The parties further agree that the SSM amount should be reduced from $398,214 to $215,234 to reflect the savings associated with the Spring and Fall 2006 OPA-funded programs.

  As a result of settlement, the total LRAM and SSM amount is $515,322.

  Schedule H to the Settlement Proposal sets out the derivation of the recalculated LRAM and SSM amounts.

- ***Evidence:*** The evidence on this issue includes the following:

  Exhibit I-2-1
  Board Staff Interrogatories #71, 72, 73, 74
  VECC Interrogatories #52, 53
  CCC Interrogatories #35, 36

10.2 Is service quality in relation to the OEB specified performance indicators acceptable?

- ***Complete Settlement*:** For the purpose of achieving settlement of all issues, the parties agree that PowerStream's service quality, in relation to OEB-specified performance indicators, is acceptable.

POWERSTREAM - 2009 EDR
Bill Impact Summary

Class	Consumption kWh	Load kW	2008 Bill	2009 Bill	Difference $	Bill Impact %	Max	Min
Residential	100		$ 23.69	$ 23.50	$ (0.19)	-0.8%	-0.8%	-1.3%
	250		38.40	38.00	(0.40)	-1.0%		
	500		62.90	62.16	(0.74)	-1.2%		
	750		87.40	86.32	(1.08)	-1.2%		
	1,000		114.14	112.65	(1.49)	-1.3%		
	1,500		168.05	165.84	(2.21)	-1.3%		
	2,000		221.96	219.02	(2.93)	-1.3%		
General Service Less Than 50 kW	1,000		129.58	127.42	(2.16)	-1.7%	-1.7%	-1.8%
	2,000		234.85	230.83	(4.02)	-1.7%		
	2,500		287.48	282.54	(4.94)	-1.7%		
	5,000		550.65	541.07	(9.58)	-1.7%		
	10,000		1,076.98	1,058.12	(18.86)	-1.8%		
	12,500		1,340.15	1,316.65	(23.50)	-1.8%		
General Service 50 to 4,999 kW	15,000	60	1,746.94	1,546.86	(200.07)	-11.5%	1.3%	-11.5%
	40,000	100	3,813.18	3,629.92	(183.26)	-4.8%		
	80,000	250	7,570.92	7,459.82	(111.09)	-1.5%		
	100,000	500	10,369.03	10,386.13	17.10	0.2%		
	400,000	1,000	35,269.02	35,498.40	229.38	0.7%		
	1,000,000	3,000	90,321.84	91,502.13	1,180.29	1.3%		
Large Use	2,800,000	7,350	246,863.14	236,045.92	(10,817.23)	-4.4%	-1.3%	-4.4%
	5,000,000	10,000	418,955.04	407,204.20	(11,750.84)	-2.8%		
	8,000,000	15,000	660,042.60	646,162.41	(13,880.19)	-2.1%		
	10,000,000	17,500	816,910.55	802,125.47	(14,785.08)	-1.8%		
	12,000,000	20,000	973,778.51	958,088.53	(15,689.97)	-1.6%		
	15,000,000	22,000	1,200,980.55	1,185,014.06	(15,966.49)	-1.3%		
Unmetered Scattered Load	250	0	38.99	38.01	(0.98)	-2.5%	-2.5%	-2.9%
	500	0	62.91	61.16	(1.75)	-2.8%		
	750	0	87.09	84.53	(2.56)	-2.9%		
	1,000	0	113.46	110.13	(3.34)	-2.9%		
	1,500	0	166.21	161.31	(4.90)	-2.9%		
	2,000	0	218.95	212.49	(6.45)	-2.9%		
Sentinel Lighting	60	0.30	9.27	9.95	0.68	7.4%	7.4%	5.7%
	180	0.50	20.16	21.30	1.15	5.7%		
	270	0.75	29.18	30.91	1.73	5.9%		
	350	1.00	37.44	39.76	2.32	6.2%		
Street Lighting	882,119	2,639	$ 147,520.73	$ 150,507.41	$ 2,986.67	2.0%	2.0%	2.0%

Bill Impacts - Monthly Consumptions

Residential

kWh	1000	**Loss Factor**	**1.0368**	**1.0299**
kW	0	**Threshold**	**800**	

	Current Rates			Proposed			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge	1	$ 13.23	$ 13.23	1	$ 13.18	$ 13.18	$ (0.05)	-0.38%	12.28%
Distribution (kWh)	1,000	$ 0.0131	$ 13.10	1,000	$ 0.0137	$ 13.70	$ 0.60	4.58%	12.77%
Distribution (kW)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
LRAM / SSM adder	1,000	$ -	$ -	1,000	$ 0.0001	$ 0.10	$ 0.10	0.00%	0.09%
Regulatory Assets (kWh)	1,000	$ -	$ -	1,000	$ (0.0023)	$ (2.300)	$ (2.30)	0.00%	-2.14%
Regulatory Assets (kW)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 26.33**			**$ 24.68**	**-$ 1.65**	**-6.27%**	**23.00%**
Other Charges	1,037	$ 0.0132	$ 13.69	1,030	$ 0.0135	$ 13.90	$ 0.22	1.59%	12.96%
Transmission charges	1,037	$ 0.0072	$ 7.46	1,030	$ 0.0077	$ 7.93	$ 0.47	6.23%	7.39%
Cost of Power Commodity (kWh)	800	$ 0.057	$ 45.60	800	$ 0.057	$ 45.60	$ -	0.00%	42.50%
Cost of Power Commodity (kWh)	237	$ 0.066	$ 15.63	230	$ 0.066	$ 15.17	$ (0.46)	-2.91%	14.14%
Total Bill before Taxes			**$ 108.71**			**$ 107.29**	**$ (1.42)**	**-1.31%**	**100%**
Total Bill Including Taxes			**$ 114.14**			**$ 112.65**	**$ (1.49)**	**-1.31%**	

General Service Less Than 50 kW

kWh	2000	**Loss Factor**	**1.0368**	**1.0299**
kW	0	**Threshold**	**750**	

	Current Rates			Proposed			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge	1	$ 29.91	$ 29.91	1	$ 29.62	$ 29.62	$ (0.29)	-0.97%	13.47%
Distribution (kWh)	2,000	$ 0.0114	$ 22.80	2,000	$ 0.0117	$ 23.40	$ 0.60	2.63%	10.64%
Distribution (kW)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
LRAM / SSM adder	2,000	$ -	$ -	2,000	$ 0.0001	$ 0.20	$ 0.20	0.00%	0.09%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ (0.0024)	$ (4.80)	$ (4.80)	0.00%	-2.18%
Regulatory Assets (kW)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 52.71**			**$ 48.42**	**-$ 4.29**	**-8.14%**	**22.02%**
Other Charges	2,074	$ 0.0132	$ 27.37	2,060	$ 0.0135	$ 27.81	$ 0.44	1.59%	12.65%
Transmission charges	2,074	$ 0.0065	$ 13.48	2,060	$ 0.0070	$ 14.42	$ 0.94	6.98%	6.56%
Cost of Power Commodity (kWh)	750	$ 0.057	$ 42.75	750	$ 0.057	$ 42.75	$ -	0.00%	19.45%
Cost of Power Commodity (kWh)	1,324	$ 0.066	$ 87.36	1,310	$ 0.066	$ 86.45	$ (0.91)	-1.04%	39.32%
Total Bill before Taxes			**$ 223.67**			**$ 219.84**	**$ (3.82)**	**-1.71%**	**100%**
Total Bill Including Taxes			**$ 234.85**			**$ 230.83**	**$ (4.02)**	**-1.71%**	

General Service 50 to 4,999 kW

kWh	80,000	**Loss Factor**	**1.0368**	**1.0299**
kW	250	**Threshold**	**750**	

	Current Rates			Proposed			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge	1	$ 302.94	$ 302.94	1	$ 84.74	$ 84.74	$ (218.20)	-72.03%	1.19%
Distribution (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	250	$ 2.3627	$ 590.68	250	$ 3.6316	$ 907.90	$ 317.23	53.71%	12.78%
LRAM / SSM adder	250	$ -	$ -	250	$ 0.0441	$ 11.03	$ 11.03	0.00%	0.15%
Regulatory Assets (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	250	$ -	$ -	250	$ (0.9971)	$ (249.28)	$ (249.28)	0.00%	-3.51%
Sub-Total			**$ 893.62**			**$ 754.39**	**-$ 139.23**	**-15.58%**	**10.62%**
Other Charges	82,944	$ 0.0132	$ 1,094.86	82,392	$ 0.0135	$ 1,112.29	$ 17.43	1.59%	15.66%
Transmission charges	250	$ 2.6400	$ 660.00	250	$ 2.8254	$ 706.35	$ 46.35	7.02%	9.94%
Cost of Power Commodity (kWh)	750	$ 0.055	$ 41.25	750	$ 0.055	$ 41.25	$ -	0.00%	0.58%
Cost of Power Commodity (kWh)	82,194	$ 0.055	$ 4,520.67	81,642	$ 0.055	$ 4,490.31	$ (30.36)	-0.67%	63.20%
Total Bill before Taxes			**$ 7,210.40**			**$ 7,104.59**	**$ (105.80)**	**-1.47%**	**100%**
Total Bill Including Taxes			**$ 7,570.92**			**$ 7,459.82**	**$ (111.09)**	**-1.47%**	

Bill Impacts - Monthly Consumptions

Large Use

kWh	2,800,000	**Loss Factor**	**1.0145**	**1.0145**
kW	7,350	**Threshold**	**750**	

	Current Rates			Proposed			IMPACT		
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Monthly Service Charge	1	$ 8,979.30	$ 8,979.30	1	$ 2,148.27	$ 2,148.27	$ (6,831.03)	-76.08%	0.96%
Distribution (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	7,350	$ 1.3036	$ 9,581.46	7,350	$ 0.4976	$ 3,657.36	$ (5,924.10)	-61.83%	1.63%
LRAM / SSM adder	7,350	$ -	$ -	7,350	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	7,350	$ -	$ -	7,350	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 18,560.76**			**$ 5,805.63**	**-$ 12,755.13**	**-68.72%**	**2.58%**
Other Charges	2,840,600	$ 0.0132	$ 37,495.92	2,840,600	$ 0.0135	$ 38,348.10	$ 852.18	2.27%	17.06%
Transmission charges	7,350	$ 3.1045	$ 22,818.08	7,350	$ 3.3223	$ 24,418.91	$ 1,600.83	7.02%	10.86%
Cost of Power Commodity (kWh)	750	$ 0.055	$ 41.25	750	$ 0.055	$ 41.25	$ -	0.00%	0.02%
Cost of Power Commodity (kWh)	2,839,850	$ 0.055	$ 156,191.75	2,839,850	$ 0.055	$ 156,191.75	$ -	0.00%	69.48%
Total Bill before Taxes			**$ 235,107.76**			**$ 224,805.64**	**$ (10,302.12)**	**-4.38%**	**100%**
Total Bill Including Taxes			**$ 246,863.14**			**$ 236,045.92**	**$ (10,817.23)**	**-4.38%**	

Bill Impacts - Monthly Consumptions

Unmetered Scattered Load

kWh	500	**Loss Factor**	**1.0368**	**1.0299**
kW	-	**Threshold**	**750**	

	Current Rates			**Proposed**			**IMPACT**		
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Monthly Service Charge	1	$ 14.35	$ 14.35	1	$ 14.14	$ 14.14	$ (0.21)	-1.46%	24.27%
Distribution (kWh)	500	$ 0.0114	$ 5.70	500	$ 0.0070	$ 3.50	$ (2.20)	-38.60%	6.01%
Distribution (kW)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
LRAM / SSM adder	500	$ -	$ -	500		$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	500	$ -	$ -	500	$ 0.0012	$ 0.60	$ 0.60	0.00%	1.03%
Regulatory Assets (kW)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 20.05**			**$ 18.24**	**-$ 1.81**	**-9.03%**	**31.31%**
Other Charges	518	$ 0.0132	$ 6.84	515	$ 0.0135	$ 6.95	$ 0.11	1.59%	11.93%
Transmission charges	518	$ 0.0067	$ 3.47	515	$ 0.0072	$ 3.71	$ 0.23	6.75%	6.36%
Cost of Power Commodity (kWh)	518	$ 0.057	$ 29.55	515	$ 0.057	$ 29.35	$ (0.20)	-0.67%	50.39%
Cost of Power Commodity (kWh)	-	$ 0.066	$ -	-	$ 0.066	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 59.91**			**$ 58.25**	**$ (1.66)**	**-2.78%**	**100%**
Total Bill Including Taxes			**$ 62.91**			**$ 61.16**	**$ (1.75)**	**-2.78%**	

Sentinel Lighting

kWh	180	**Loss Factor**	**1.0368**	**1.0299**
kW	0.50	**Threshold**	**750**	

	Current Rates			**Proposed**			**IMPACT**		
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Monthly Service Charge	1.0	$ 2.01	$ 2.01	1.0	$ 1.98	$ 1.98	$ (0.03)	-1.49%	9.76%
Distribution (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	0.5	$ 6.0842	$ 3.04	0.5	$ 11.0447	$ 5.52	$ 2.48	81.53%	27.22%
LRAM / SSM adder	0.5	$ -	$ -	0.5		$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	0.5	$ -	$ -	0.5	$ (2.8005)	$ (1.40)	$ (1.40)	0.00%	-6.90%
Sub-Total			**$ 5.05**			**$ 6.10**	**$ 1.05**	**20.78%**	**30.08%**
Other Charges	187	$ 0.0132	$ 2.46	185	$ 0.0135	$ 2.50	$ 0.04	1.59%	12.34%
Transmission charges	0.5	$ 2.0877	$ 1.04	0.5	$ 2.2325	$ 1.12	$ 0.07	6.94%	5.50%
Cost of Power Commodity (kWh)	187	$ 0.057	$ 10.64	185	$ 0.057	$ 10.57	$ (0.07)	-0.67%	52.08%
Cost of Power Commodity (kWh)	-	$ 0.066	$ -	-	$ 0.066	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 19.20**			**$ 20.29**	**$ 1.09**	**5.68%**	**100%**
Total Bill Including Taxes			**$ 20.16**			**$ 21.30**	**$ 1.15**	**5.68%**	

Street Lighting

kWh	882,119	**Loss Factor**	**1.0368**	**1.0299**
kW	2,639.22	**Threshold**	**750**	

	Current Rates			**Proposed**			**IMPACT**		
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Monthly Service Charge	63,805	$ 0.84	$ 53,595.97	63,805	$ 0.83	$ 52,957.92	$ (638.05)	-1.19%	36.95%
Distribution (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	2,639	$ 3.4686	$ 9,154.41	2,639	$ 5.5581	$ 14,669.07	$ 5,514.66	60.24%	10.23%
LRAM / SSM adder	2,639	$ -	$ -	2,639		$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	-	$ -	$ -	-	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	2,639	$ -	$ -	2,639	$ (0.8317)	$ (2,195.04)	$ (2,195.04)	0.00%	-1.53%
Sub-Total			**$ 62,750.38**			**$ 65,431.94**	**$ 2,681.57**	**4.27%**	**45.65%**
Other Charges	914,581	$ 0.0132	$ 12,072.47	908,494	$ 0.0135	$ 12,264.67	$ 192.20	1.59%	8.56%
Transmission charges	2,639	$ 2.0148	$ 5,317.51	2,639	$ 2.1559	$ 5,689.90	$ 372.39	7.00%	3.97%
Cost of Power Commodity (kWh)	750	$ 0.057	$ 42.75	750	$ 0.057	$ 42.75	$ -	0.00%	0.03%
Cost of Power Commodity (kWh)	913,831	$ 0.066	$ 60,312.84	907,744	$ 0.066	$ 59,911.12	$ (401.72)	-0.67%	41.80%
Total Bill before Taxes			**$ 140,495.94**			**$ 143,340.39**	**$ 2,844.45**	**2.02%**	**100%**
Total Bill Including Taxes			**$ 147,520.73**			**$ 150,507.41**	**$ 2,986.67**	**2.02%**	

LV Wheeling Costs Allocation - TEST YEAR - 2009

LV charges to be Allocated		Transmission Connection Rate		Loss Factor	Basis for Allocation				Allocated LV charges
860,825		$ per kwh / kw			kwh	kw	$	%	$
Residential	*$/kWh*	$	0.0023	1.0299	2,095,280,722	0	$4,819,146	31.5%	$271,286
GS<50	*$/kWh*	$	0.0021	1.0299	827,140,023	0	$1,736,994	11.4%	$97,781
GS>50	*$/kW*	$	0.8391		3,909,095,504	10,189,730	$8,550,203	55.9%	$481,320
Time of use	*$/kW*	$	0.8670		0	0	$0	0.0%	$0
Large Use	*$/kW*	$	0.9917		31,414,814	82,809	$82,121	0.5%	$4,623
USL	*$/kWh*	$	0.0023	1.0299	8,440,204	0	$19,412	0.1%	$1,093
Sentinel Lighting	*$/kW*	$	0.7115	1.0299	703,350	1,750	$1,245	0.0%	$70
Street Lighting	*$/kW*	$	0.6524	1.0299	43,607,722	126,683	$82,648	0.5%	$4,653
Total					6,915,682,340	10,400,971	$15,291,769	100.0%	$860,825

Rates - LV / Wheeling Adjustment - 2009

		2009			LV Wheeling Rates	
		LV charge allocated, $	kwh	kw	$/kwh	$/kw
Residential	*$/kWh*	$ 271,286	2,034,450,648	-	0.0001	
GS<50	*$/kWh*	$ 97,781	803,126,540	-	0.0001	
GS>50	*$/kW*	$ 481,320	3,909,095,504	10,189,730		0.0472
Time of use	*$/kW*	$ -	-	-		
Large Use	*$/kW*	$ 4,623	31,414,814	82,809		0.0558
USL	*$/kWh*	$ 1,093	8,195,169	-	0.0001	
Sentinel Lighting	*$/kW*	$ 70	682,931	1,750		0.0401
Street Lighting	*$/kW*	$ 4,653	42,341,705	126,683		0.0367
Total		**$ 860,825**	**6,829,307,310**	**10,400,971**		

Conditions of Service and Related Amendments

OEB Decision

In its Decision the Board directs that PowerStream amend its Conditions of Service and related contracts going forward in a manner that clearly reflects the intent described by the PowerStream witnesses in this hearing. PowerStream shall file, for convenience, the amended sections of the Conditions of Service and related Terms of Reference Letters or other contracts as part of its draft rate order.

PowerStream's Conditions of Service

On page 7 of its Decision the OEB states:

> "The SSMWG argued that PowerStream's Conditions of Service and contracts (filed in the form of a Terms of Reference Letter in SSMWG Schedule 3-1), are unclear and misleading and do not indicate that a multi-unit building has the option of bulk metering. On cross-examination the witness for PowerStream denied this was the meaning or intent of the Conditions of Service and offered to amend the Conditions of Service to clarify the wording. (TR pg 165).

The amended Section 2.3.7.3.5 of PowerStream's Condition of Service is presented below.

Condition of Service (excerpts)

2.3.7.3.5 Multi-Unit Residential Suite Buildings

Under Ontario Regulation 442/07, all new multiunit condominium buildings must be either individually metered by the licensed distributor or smart sub-metered by an alternative licensed service provider. For existing condominiums the installation of individual smart meters or smart sub-meters is at the discretion of the condominium's board of directors.

Where individual units of an existing or new multiunit condominium building are individually metered by PowerStream, each unit will become a residential customer of PowerStream and each unit and the common areas must have a separate account with PowerStream.

Where an existing or new multiunit condominium building is sub-metered by an alternative licensed service provider, the condominium continues to be the customer of PowerStream and will receive a single bill based on the measurement of the bulk (master) meter. The condominium corporation, which is responsible for the distribution of electricity on the consumer side of the bulk (master) meter, is an exempt distributor under section 4.0.1 of Ontario Regulation 161/99—*Definitions and Exemptions* (made under the Act). The smart sub-metering provider will then issue a bill to each unit and the common areas based on the consumption of the unit or common area.

Where all units within a multiunit building are individually metered, the building owner shall provide a secure meter room or suitable enclosure within the building for the installation of a sub metering system.

This room or enclosure will have adequate lighting, a 120 volt outlet and a dedicated analog telephone line for meter interrogation purposes.

The building owner may opt for individual self-contained meters attached to individual bases, to a load centre as defined in the PowerStream Standards or a Sub-metered system.

Requests for sub-metered systems must be submitted to PowerStream's Metering Department for approval prior to construction. Any such system will be "Measurement Canada" approved and sealed, and be complete with instrument transformer and meter register accuracy test certificates.

PowerStream's Contracts

On page 7 of its Decision the OEB states that:

> "On the issue of contract exclusivity, there were also some questions raised as to the clarity of provisions in the PowerStream contracts regarding the freedom of the condominium corporation to exit a contract for another service provider. Again the PowerStream witnesses indicated that the condominium corporation could choose another service provider and that there are no barriers to exit. (TR pg 77)"

The amended Terms of Reference letters are attached.

TERMS OF REFERENCE LETTER

Suite Meter Installation and Service Provider

XYZ DEVELOPMENT INC. (the Developer) engages PowerStream Inc. (PowerStream) for the purpose of the installation and administration of separate electricity meters for individual condominium units in **XYZ DEVELOPMENT INC.**

PowerStream will provide the following to the Developer in accordance with the following and, if any, the attached terms and conditions with respect to the Equipment:

- The installation of smart suite meters (referred to as the Equipment);
- Data acquisition; data storage; data management; data transfer to PowerStream for billing purposes; operations, maintenance, troubleshooting and repair work to maintain the metering system; and all account management activities, including scheduled meter readings, billing, revenue collection and service disconnect/reconnect as required;
- Meters will meet the same Measurement Canada requirements for accuracy and durability as all other customer meters installed throughout the PowerStream service territory;
- PowerStream fully warrants the quality of our products and services as your local distribution electric utility; and
- Individual unit condominium owners will receive a bill for their electricity service directly from PowerStream.

The Ontario Energy Board licenses PowerStream to provide distribution services and regulates PowerStream's rates and practices through a public hearing process.

The Equipment installation will comply with PowerStream's Conditions of Service section 2.3.7, and end-use customer tariffs and charges will comply with PowerStream's Conditions of Service section 2.4, see attached.

Either Party may terminate this Terms of Reference upon 90 days written notice to the other Party. Upon termination the Developer shall allow PowerStream to remove the Equipment.

The Parties agree to the content of this document by their authorized signatures below.

XYZ DEVELOPMENT INC.	**PowerStream Inc.**
Signature:__________________	Signature:__________________
Print Name: ________________	Print Name:_________________
Title:______________________	Title:_______________________
Date: _____________________	Date:______________________

TERMS OF REFERENCE LETTER

Suite Meter Installation and Service Provider

ABC CONDOMINIUM CORPORATION (the Condo Corp.) engages PowerStream Inc. (PowerStream) for the purpose of the installation and administration of separate electricity meters for individual condominium units in **XYZ Condominium**.

PowerStream will provide the following to the Condo Corp. in accordance with the following and, if any, the attached terms and conditions with respect to the Equipment:

- The installation of smart suite meters (referred to as the Equipment);
- Data acquisition; data storage; data management; data transfer to PowerStream for billing purposes; operations, maintenance, troubleshooting and repair work to maintain the metering system; and all account management activities, including scheduled meter readings, billing, revenue collection and service disconnect/reconnect as required;
- Meters will meet the same Measurement Canada requirements for accuracy and durability as all other customer meters installed throughout the PowerStream service territory;
- PowerStream fully warrants the quality of our products and services as your local distribution electric utility; and
- Individual unit condominium owners will receive a bill for their electricity service directly from PowerStream.

The Ontario Energy Board licenses PowerStream to provide distribution services and regulates PowerStream's rates and practices through a public hearing process.

The Equipment installation will comply with PowerStream's Conditions of Service section 2.3.7, and end-use customer tariffs and charges will comply with PowerStream's Conditions of Service section 2.4, see attached.

Either Party may terminate this Terms of Reference upon 90 days written notice to the other Party. Upon termination the Condo Corp shall allow PowerStream to remove the Equipment.

The Parties agree to the content of this document by their authorized signatures below.

ABC CONDOMINIUM CORPORATION

Signature:__________________
Print Name: ________________
Title:______________________
Date: _____________________

PowerStream Inc.

Signature:_________________
Print Name:________________
Title:______________________
Date:______________________

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0244

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 PowerStream Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2009.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Cathy Spoel
Member

RATE ORDER

PowerStream Inc. ("PowerStream" or the "Applicant") is a licensed distributor of electricity providing service to consumers within its licensed service area, the cities of Barrie and Vaughan and the towns of Aurora, Markham and Richmond Hill. On October 10, 2008 PowerStream filed an application under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that PowerStream charges for electricity distribution, to be effective May 1, 2009.

The application did not encompass any aspects of the merger with Barrie Hydro Distribution Inc. ("Barrie Hydro") approved under Board file EB-2008-0335. Distribution rates for Barrie Hydro continue under a separate Board approval.

The Board assigned File Number EB-2008-0244 to the application. The Board issued a Notice of Application and Hearing dated October 24, 2008. On February 3, 2009, PowerStream filed an updated application.

A Settlement Conference was held on May 19, 2009. Settlement was achieved on all but one sub-issue, concerning PowerStream's individual suite metering activities and the revenue requirement impacts of these activities. The Board reviewed the Settlement Proposal and accepted the agreement as filed by the parties. To address the remaining sub-issue, the Board held an oral hearing on June 15, 2009.

The Board's Majority Decision regarding the application was issued on July 27, 2009 accompanied by a Minority Decision. In the Majority Decision, the Board ruled on the remaining issue and ordered that PowerStream file a Draft Rate Order reflecting the Settlement Proposal and the Board's findings.

In the Majority Decision, the Board also directed PowerStream to amend its Conditions of Service and related Terms of Reference Letters or other contracts that apply to suite metering in Multi-Unit Residential Suite Buildings.

PowerStream filed a Draft Rate Order on July 31, 2009. Intervenors in this proceeding had the opportunity to file comments within 7 days from the date of the filing of the Draft Rate Order.

The Board received comments from the Smart Sub Metering Working Group (SSMWG) which raised concerns on the wording PowerStream used in its proposed amendments to its Conditions of Service. By letter dated August 12, 2009, PowerStream indicated that it would accept the wording change as suggested by the SSMWG.

The Board has reviewed the information provided and the proposed Tariff of Rates and Charges and is satisfied that the document accurately reflects the Settlement Proposal and the Board's Majority Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Rate Order is approved, effective May 1, 2009 but implemented on

September 1, 2009, for electricity consumed or estimated to have been consumed on and after September 1, 2009.

2. The Tariff of Rates and Charges set out in Appendix “A” of this Order supersedes all previous distribution rate schedules approved by the Board for PowerStream Inc. and is final.

3. PowerStream Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. PowerStream Inc. shall amend section 2.3.7.3.5 of its Conditions of Service as filed with PowerStream’s Draft Rate Order and the related Terms of Reference Letters, amended with its August 12, 2009 filing (attached as Appendix “B”).

DATED at Toronto, August 13, 2009
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix “A”

To The Rate Order Arising from Decision and Order
EB-2008-0244

The Tariff of Rates and Charges

PowerStream Inc.

August 13, 2009

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

Implementation September 1, 2009

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

EB-2008-0244

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

IMPLEMENTATION DATES

DISTRIBUTION RATES – September 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – September 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – September 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – September 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service.

General Service Less Than 50 kW

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.

General Service 50 to 4,999 kW

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.

Large Use

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.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is 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 customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting

This classification refers to an unmetered lighting load supplied to a sentinel light.

Street Lighting

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, 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.

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

Implementation September 1, 2009

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

EB-2008-0244

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.85
Smart Meter Funding Adder	$	1.04
Smart Meter Rate Rider – effective until April 30, 2010	$	0.29
Distribution Volumetric Rate	$/kWh	0.0135
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kWh	0.0002
LRAM/SSM Rate Rider – effective until April 30, 2010	$/kWh	0.0001
Deferral Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0023)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	28.29
Smart Meter Funding Adder	$	1.04
Smart Meter Rate Rider – effective until April 30, 2010	$	0.29
Distribution Volumetric Rate	$/kWh	0.0116
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kWh	0.0001
LRAM/SSM Rate Rider – effective until April 30, 2010	$/kWh	0.0001
Deferral Account Rate Rider – effective until April 30, 2011	$/kWh	(0.0024)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0022
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	83.41
Smart Meter Funding Adder	$	1.04
Smart Meter Rate Rider – effective until April 30, 2010	$	0.29
Distribution Volumetric Rate	$/kW	3.5078
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kW	0.1238
LRAM/SSM Rate Rider – effective until April 30, 2010	$/kW	0.0441
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	(0.9971)
Retail Transmission Rate – Network Service Rate	$/kW	1.9489
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8765
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009
Implementation September 1, 2009

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EB-2008-0244

Large Use

Service Charge	$	2,146.94
Smart Meter Funding Adder	$	1.04
Smart Meter Rate Rider – effective until April 30, 2010	$	0.29
Distribution Volumetric Rate	$/kW	1.0913
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kW	(0.5937)
Deferral Account Rate Rider for existing customers only – effective until April 30, 2011	$/kW	(1.71)
Retail Transmission Rate – Network Service Rate	$/kW	2.2864
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0359
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	14.14
Distribution Volumetric Rate	$/kWh	0.0087
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kWh	(0.0017)
Deferral Account Rate Rider – effective until April 30, 2011	$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.98
Distribution Volumetric Rate	$/kW	9.3165
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kW	1.7282
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	(2.8005)
Retail Transmission Rate – Network Service Rate	$/kW	1.4893
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7432
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.83
Distribution Volumetric Rate	$/kW	4.8386
Foregone Distribution Revenue Rate Rider – effective until April 30, 2010	$/kW	0.7195
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	(0.8317)
Retail Transmission Rate – Network Service Rate	$/kW	1.4744
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6815
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009
Implementation September 1, 2009

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

EB-2008-0244

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	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
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
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary Service install and remove – overhead – no transformer	$	500.00
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)

Retail Service Charges (if applicable)

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Appendix "B"

To The Rate Order Arising from Decision and Order
EB-2008-0244

Condition of Service (excerpts)

PowerStream Inc.

August 13, 2009

Condition of Service (excerpts)

2.3.7.3.5 Multi-Unit Residential Suite Buildings

Under Ontario Regulation 442/07, all new multiunit condominium buildings must be either individually metered by the licensed distributor or smart sub-metered by an alternative licensed service provider. For existing condominiums the installation of individual smart meters or smart sub-meters is at the discretion of the condominium's board of directors.

Where individual units of an existing or new multiunit condominium building are individually metered by PowerStream, each unit will become a residential customer of PowerStream and each unit and the common areas must have a separate account with PowerStream.

Where an existing or new multiunit condominium building is sub-metered by an alternative licensed service provider, the condominium continues to be the customer of PowerStream and will receive a single bill based on the measurement of the bulk (master) meter. The condominium corporation, which is responsible for the distribution of electricity on the consumer side of the bulk (master) meter, is an exempt distributor under section 4.0.1 of Ontario Regulation 161/99—*Definitions and Exemptions* (made under the Act). The smart sub-metering provider will then issue a bill to each unit and the common areas based on the consumption of the unit or common area.

Where all units within a multiunit building are individually metered, the building owner shall provide a secure meter room or suitable enclosure within the building for the installation of a sub metering system.

This room or enclosure will have adequate lighting, a 120 volt outlet and a dedicated analog telephone line for meter interrogation purposes.

The building owner may opt for individual self-contained meters attached to individual bases, to a load centre as defined in the PowerStream Standards or a Sub-metered system.

TERMS OF REFERENCE LETTER

Suite Meter Installation and Service Provider

XYZ DEVELOPMENT INC. (the Developer) engages PowerStream Inc. (PowerStream) for the purpose of the installation and administration of separate electricity meters for individual condominium units in **XYZ DEVELOPMENT INC.**

PowerStream will provide the following to the Developer in accordance with the following and, if any, the attached terms and conditions with respect to the Equipment:

- The installation of smart suite meters (referred to as the Equipment);
- Data acquisition; data storage; data management; data transfer to PowerStream for billing purposes; operations, maintenance, troubleshooting and repair work to maintain the metering system; and all account management activities, including scheduled meter readings, billing, revenue collection and service disconnect/reconnect as required;
- Meters will meet the same Measurement Canada requirements for accuracy and durability as all other customer meters installed throughout the PowerStream service territory;
- PowerStream fully warrants the quality of our products and services as your local distribution electric utility; and
- Individual unit condominium owners will receive a bill for their electricity service directly from PowerStream.

The Ontario Energy Board licenses PowerStream to provide distribution services and regulates PowerStream's rates and practices through a public hearing process.

The Equipment installation will comply with PowerStream's Conditions of Service section 2.3.7, and end-use customer tariffs and charges will comply with PowerStream's Conditions of Service section 2.4, see attached.

Either Party may terminate this Terms of Reference upon 90 days written notice to the other Party. Upon termination the Developer shall allow PowerStream to remove the Equipment.

The Parties agree to the content of this document by their authorized signatures below.

XYZ DEVELOPMENT INC.

Signature:__________________
Print Name: ________________
Title:______________________
Date: _____________________

PowerStream Inc.

Signature:__________________
Print Name:_________________
Title:_______________________
Date:______________________

TERMS OF REFERENCE LETTER

Suite Meter Installation and Service Provider

ABC CONDOMINIUM CORPORATION (the Condo Corp.) engages PowerStream Inc. (PowerStream) for the purpose of the installation and administration of separate electricity meters for individual condominium units in **XYZ Condominium**.

PowerStream will provide the following to the Condo Corp. in accordance with the following and, if any, the attached terms and conditions with respect to the Equipment:

- The installation of smart suite meters (referred to as the Equipment);
- Data acquisition; data storage; data management; data transfer to PowerStream for billing purposes; operations, maintenance, troubleshooting and repair work to maintain the metering system; and all account management activities, including scheduled meter readings, billing, revenue collection and service disconnect/reconnect as required;
- Meters will meet the same Measurement Canada requirements for accuracy and durability as all other customer meters installed throughout the PowerStream service territory;
- PowerStream fully warrants the quality of our products and services as your local distribution electric utility; and
- Individual unit condominium owners will receive a bill for their electricity service directly from PowerStream.

The Ontario Energy Board licenses PowerStream to provide distribution services and regulates PowerStream's rates and practices through a public hearing process.

The Equipment installation will comply with PowerStream's Conditions of Service section 2.3.7, and end-use customer tariffs and charges will comply with PowerStream's Conditions of Service section 2.4, see attached.

Either Party may terminate this Terms of Reference upon 90 days written notice to the other Party. Upon termination the Condo Corp shall allow PowerStream to remove the Equipment.

The Parties agree to the content of this document by their authorized signatures below.

ABC CONDOMINIUM CORPORATION

Signature:___________________
Print Name: _________________
Title:_______________________
Date: ______________________

PowerStream Inc.

Signature:__________________
Print Name:_________________
Title:_______________________
Date:_______________________

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

Ontario

EB-2008-0160

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 Barrie Hydro Distribution Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

Introduction

Barrie Hydro Distribution Inc. ("Barrie") is a licensed distributor of electricity providing service to consumers within its licensed service area. Barrie filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2009.

Barrie is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2008, the Board announced the establishment of a new multi-year electricity distribution rate-setting plan, the 3rd Generation Incentive Rate Mechanism ("IRM") process, that will be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review. As part of the plan, Barrie is one of the electricity distributors to have its rates adjusted for 2009 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 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on July 14, 2008, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008, and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (together the "Reports"). Among other things, the Reports contained the relevant guidelines for 2009 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process.

Notice of Barrie's rate application was given through newspaper publication in Barrie's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. No letters of comment were received. The Vulnerable Energy Consumers Coalition ("VECC") and Board staff posed interrogatories and made submissions. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Barrie's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Barrie, the Board has applied the policies described in the Reports.

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 Barrie's utility specific stretch factor of 0.2. Based on the final 2008 data published by Statistics Canada, the Board has established the price escalator to be 2.3%. The resulting price cap index adjustment is therefore 1.38%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. A change in the federal income tax rate effective January 1, 2009 was incorporated into the rate model and reflected in distribution rates.

The Federal Budget enacted on February 3, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009, and a change in the capital cost allowance (CCA) applicable to certain computer equipment and related system software (CCA class 50) acquired between January 27, 2009 and February 2011. The Board has considered these fiscal changes and determined that the rate model will be adjusted to reflect the increase in the federal small business income limit for affected distributors. With regard to the change in the CCA, the Board notes that this change would be captured in the revenue requirement calculation as it relates to smart meters when a distributor applies for cost recovery for the applicable investment period. For other computer equipment and related system software in class 50, the Board concludes that this adjustment is not required since it does not appear to be material.

The price cap index adjustment does not apply to the following components of distribution rates:

- Rate Riders;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Retail Service Charges;
- Loss Factors; and
- Smart Meter Funding Adder.

Bill 44 – Payments in Lieu of Taxes (PILs)

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic Outlook and Fiscal Review. Bill 44, the enabling legislation, received Royal Assent on May 14, 2008, and was promulgated in The Ontario Gazette on May 24, 2008. The resulting tax provision changes resulted in a decrease in PILs for Barrie.

The Board’s Decision in EB-2007-0746, Barrie’s 2008 cost of service application (“2008 CoS”), was issued on March 25, 2008, prior to Bill 44 being enacted. Accordingly, Barrie’s revenue requirement was calculated on the tax rates that existed prior to the enactment of Bill 44.

Board staff noted that some 2008 CoS proceedings required more time to process than others. As a result, some applications that were filed with the Board at around the same time as Barrie had filed its 2008 CoS application had their Decisions issued after May 24, 2008, with their resulting electricity distribution rates reflecting the lower tax rates. Board staff submitted that for consistency and fairness across electricity distributors, the difference in PILs Barrie is collecting in its distribution rates as a result of its 2008 CoS Decision having been issued before May 24, 2008, should be removed as of May 1, 2009. Board staff also submitted that the additional amounts Barrie collected in the 2008 rate year should remain with Barrie, as it appropriately reflected the Board Decision (EB-2007-0746) for that rate year. Board staff further submitted that Barrie's distribution rates should be adjusted to reduce the revenues collected by $80,912.

Barrie agreed with Board staff's submission and the calculated amount.

The Board finds Board staff's proposed adjustment appropriate and has reflected these changes in the attached draft Tariff of Rates and Charges (Appendix A).

Rural or Remote Electricity Rate Protection Adjustment

In accordance with Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) the Board issued a Decision on December 17, 2008 setting out the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

In a letter dated December 17, 2008 the Board directed distributors that had a rate application before the Board to file a request with the Board that the RRRP charge in their tariff sheet be revised to 0.13 cent per kilowatt-hour effective May 1, 2009.

Barrie complied with this directive. The rate model was adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law.

Barrie reports that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc.

Barrie requested the standard smart meter funding adder of $1.00 per metered customer per month, which is intended to provide funding in the case where a distributor may be in the early stages of planning and may not yet have sufficient cost information to request a utility-specific funding adder. The Board approves the funding adder as proposed by Barrie. This new funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. Barrie's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.00 per metered customer per month is intended to provide funding for Barrie's smart metering activities in the 2009 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Barrie applies for the recovery of these costs.

Revenue-to-Cost Ratios

Revenue-to-cost ratios ("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. In its EB-2007-0746 Decision, the Board made findings with regard to Barrie's Ratios and directed that they be incrementally adjusted over time, starting in 2008 (the "2008 Ratios").

Barrie proposed to adjust its Ratios as shown in Column 2 of Table 1.

Table 1 – Barrie's Revenue-to-Cost Ratios (%)

Rate Class	2008 Ratio Column 1	Proposed 2009 Ratio Column 2	Target Range Column 3
Residential	113.5	112.3	85 – 115
GS < 50 kW	97.5	97.4	80 – 120
GS 50 – 4,999 kW	86.3	86.1	80 – 180
Large Use	-	85.7	70 – 120
Street Lighting	25.0	40.0	70 – 120
USL	98.6	98.1	80 – 120

VECC noted in its submission that Barrie's Large Use rate class did not exist at the time that Barrie's Cost Allocation Informational filing was prepared. While VECC described Barrie's approach to estimate the Ratio of the Large Use rate class for the purpose of its 2009 rate application as simplistic, VECC also noted that it was "probably acceptable."

Board staff noted in its submission that, for the purpose of calculating the Ratio adjustments, the rate model allocates the low voltage charges and transformer allowance "costs" across rate classes in a way that may differ from how they were allocated in Barrie's 2008 CoS. Board staff submitted that this difference is immaterial and that Barrie's proposed Ratio adjustments are reasonable and in compliance with its 2008 CoS Decision (EB-2007-0746). Board staff also noted that the rate model will be adjusted next year to enable distributors to reflect how the low voltage charges and transformer allowance "costs" were allocated for the purpose of calculating their Ratios in their 2008 CoS. Accordingly, any differences in the calculation of the Ratios in the 2009 rate model will be reversed in the 2010 rate model next year.

In its submission, VECC concurred with Board staff's observations regarding the allocation of the transformer allowance "costs" and low voltage charges. VECC however noted two additional concerns with the rate model.

First, VECC submitted that the Ratios shown in Column 1 of Table 1 should be used as the starting point for the 2009 Ratio adjustments. In contrast, the rate model estimates what the actual 2008 Ratios were and uses these estimates as the starting point for the 2009 Ratio adjustments. VECC submitted that the approach underlying the rate model only works if the billing parameters (i.e., kWhs, kWs and customer count) represent close to the same proportions by rate class in 2009 as they did in Barrie's Cost Allocation Informational filing. VECC submitted that the Board should direct Board staff to revisit this part of the rate model next year.

Second, VECC noted that Barrie's Cost Allocation Informational filing allocated distribution service revenues and miscellaneous revenues across rate classes, whereas the rate model only allocates distribution service revenues. VECC noted that the impact of this difference in methodology is likely small. VECC submitted that the Board should direct Board staff to revisit this part of the rate model next year.

In light of the adjustments proposed by Board staff to the rate model next year, and VECC's additional two proposed changes in methodology for next year, VECC submitted that there was no need to make any changes to Barrie's proposed Ratio adjustments at this time.

The Board sees merits in Board staff's proposed adjustments to the rate model and VECC's proposed additional adjustments. The Board expects Board staff to consider those adjustments when preparing the rate model for next year. The Board notes that VECC and Board staff recommended that Barrie's proposed 2009 Ratio adjustments be approved as submitted. The Board approves Barrie's proposed rate adjustments as they follow the direction and intent of the 2008 cost of service Decision (EB-2007-0746) and are reasonable.

Retail Transmission Service Rates

On October 22, 2008 the Board issued a Guideline for *Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") which provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust Retail Transmission Service Rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs").

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new UTRs for Ontario transmitters, effective January 1, 2009. The Board approved an increase of 11.3% to the wholesale transmission network rate, an increase of 18.6% to the wholesale transmission line connection rate, and an increase of 0.6% to the wholesale transformation connection rate. The combined change in the wholesale transmission line connection and transformation connection rates is an increase of about 5%.

Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are also 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., deferral accounts 1584 and 1586).

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586.

Barrie proposed to increase its RTSR – Network Service Rates by 11.0% and to increase its RTSR – Line and Transformation Connection Service Rates by 5%.

The Board is providing Barrie with a rate model (spreadsheet) 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 2008 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

Barrie’s new distribution rates will be effective May 1, 2009. The Board Orders that:

1. Barrie shall review the draft Tariff of Rates and Charges set out in Appendix A. Barrie 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 seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Barrie to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

2. The draft Tariff of Rates and Charges set out in Appendix A of this Order will become final, effective May 1, 2009, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009.

3. The Tariff of Rates and Charges set out in Appendix A of this Order shall supersede all previous distribution rate schedules approved by the Board for Barrie and is final in all respects.

4. Barrie shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

If the Board receives a submission by Barrie to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Barrie and will issue a final Tariff of Rates and Charges.

DATED at Toronto, March 12, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

EB-2008-0160

March 12, 2009

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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

EB-2008-0160

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility's Conditions of Service.

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

General Service 50 to 4,999 kW
This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

General Service 50 to 4,999 kW TOU
This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW and who has an electrical service of at least 600 amps at 600/347 volts or 1600 amps at 208/120 volts. If the customer meets these criteria then an interval meter is required. Further servicing details are available in the utility's Conditions of Service.

Large Use
This classification refers to an account whose monthly average peak demand is equal to or greater than or is expected to be equal to or greater than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW. As determined by Barrie Hydro Distribution Inc. because of the type of connection or location a meter is not feasible in these situations. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility's Conditions of Service.

Standby Power
This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service.

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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

EB-2008-0160

Street Lighting

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the utility's Conditions of Service.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	16.43
Service Charge Rate Rider for Tax Change– effective until April 30, 2010	$	(0.01)
Distribution Volumetric Rate	$/kWh	0.0146
Deferral Account Rate Rider – effective until April 30, 2011	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	16.88
Service Charge Rate Rider for Tax Change– effective until April 30, 2010	$	(0.01)
Distribution Volumetric Rate	$/kWh	0.0170
Deferral Account Rate Rider – effective until April 30, 2011	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	392.05
Service Charge Rate Rider for Tax Change– effective until April 30, 2010	$	(0.34)
Distribution Volumetric Rate	$/kW	2.1038
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	0.0752
Distribution Volumetric Rate Rider for Tax Change– effective until April 30, 2010	$/kW	(0.0018)
Retail Transmission Rate – Network Service Rate	$/kW	1.9136
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7778
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0160

General Service 50 to 4,999 kW Time of Use

Service Charge	$	392.05
Service Charge Rate Rider for Tax Change– effective until April 30, 2010	$	(0.34)
Distribution Volumetric Rate	$/kW	2.1038
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	0.0752
Distribution Volumetric Rate Rider for Tax Change– effective until April 30, 2010	$/kW	(0.0018)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5403
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.3600
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	9,553.71
Service Charge Rate Rider for Tax Change– effective until April 30, 2010	$	(8.19)
Distribution Volumetric Rate	$/kW	0.9701
Tax Change Rate Rider – effective until April 30, 2010	$/kW	(0.0008)
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	0.0000
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5473
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.3665
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	7.84
Service Charge Rate Rider for Tax Change– effective until April 30, 2010	$	(0.01)
Distribution Volumetric Rate	$/kWh	0.0166
Deferral Account Rate Rider – effective until April 30, 2011	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Standby Power – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	2.6471

Street Lighting

Service Charge (per connection)	$	1.58
Distribution Volumetric Rate	$/kW	6.2830
Deferral Account Rate Rider – effective until April 30, 2011	$/kW	0.0666
Distribution Volumetric Rate Rider for Tax Change– effective until April 30, 2010	$/kW	(0.0054)
Retail Transmission Rate – Network Service Rate	$/kW	1.5117
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Barrie Hydro Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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

EB-2008-0160

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – no disconnection	$	15.00
Disconnect/Reconnect at Meter - during Regular Hours	$	30.00
Disconnect/Reconnect at Meter - after Regular Hours	$	185.00
Disconnect/Reconnect at Pole - during Regular Hours	$	185.00
Disconnect/Reconnect at Pole - after Regular Hours	$	415.00
Service Call – customer owned equipment – charge based on time and materials		
Service Call – after regular hours – charge based on time and materials		
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
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)

Retail Service Charges (if applicable)

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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

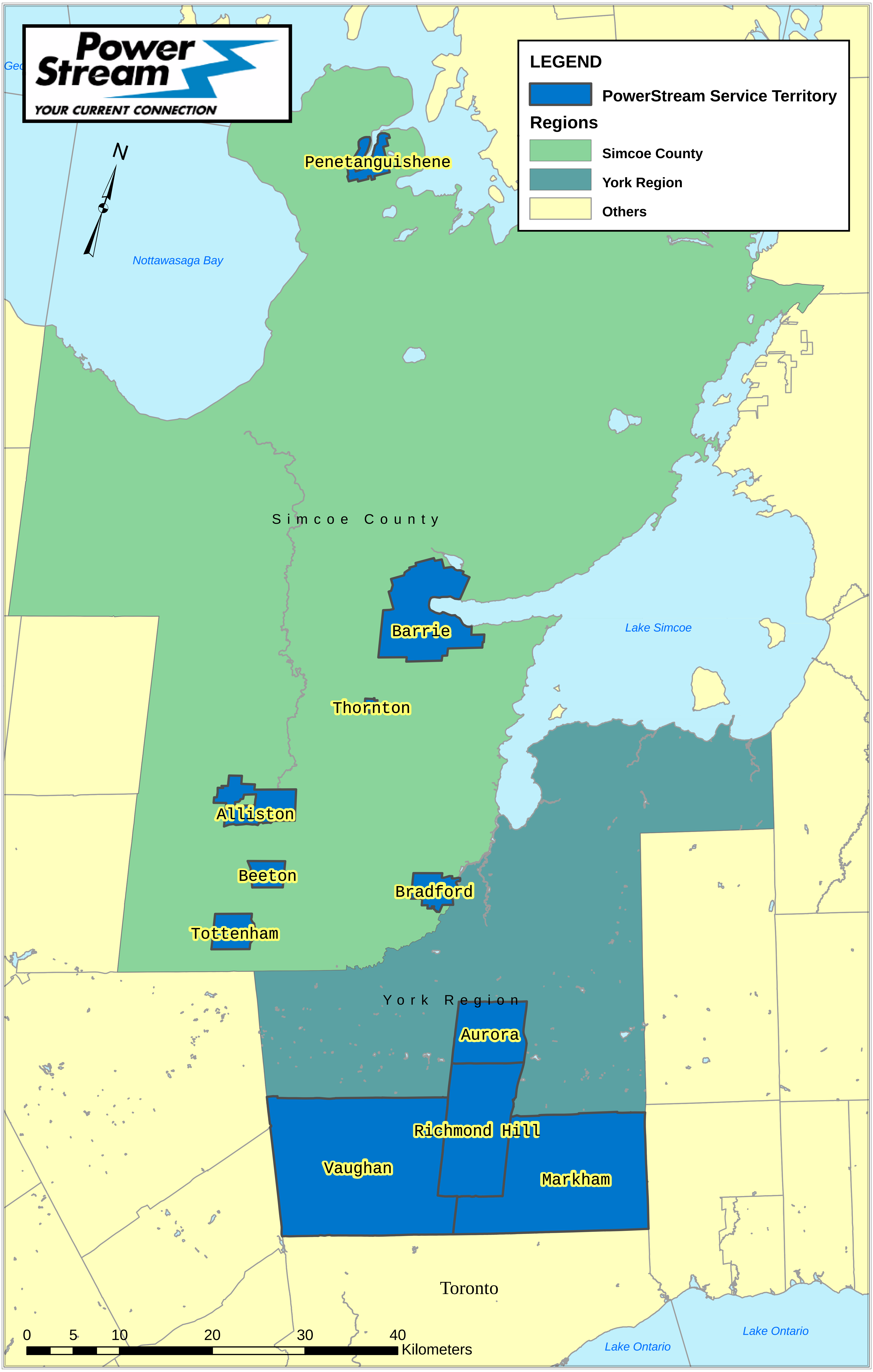
LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0565
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0462
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

EB-2012-0161
PowerStream Inc.
Appendix 1
Schedule 4
Filed May 4, 2012

Schedule 4

MAP OF DISTRIBUTION SYSTEM


Power Stream
YOUR CURRENT CONNECTION
LEGEND
PowerStream Service Territory
Regions
Simcoe County
York Region
Others
N
Nottawasaga Bay
Penetanguishene
Simcoe County
Barrie
Lake Simcoe
Thornton
Alliston
Beeton
Bradford
Tottenham
York Region
Aurora
Richmond Hill
Vaughan
Markham
Toronto
Lake Ontario
Lake Ontario
0
5
10
20
30
40
Kilometers

Schedule 5

LISTS OF NEIGHBOURING UTILITIES

PowerStream Inc.
List of Neighbouring Utilities

PowerStream Inc.:

- Veridian Connections Inc.
- Whitby Hydro Electric Corporation
- Toronto Hydro Electric Corporation
- Hydro One Brampton Networks Inc.
- Enersource Hydro Mississauga Inc.
- Newmarket Hydro Ltd.
- Hydro One Network Inc.

Former Barrie Hydro Distribution Inc.:

- Innisfil Hydro
- Hydro One Network Inc.

Schedule 6

EXPLANATION OF HOST OR EMBEDDED UTILITIES

PowerStream Inc. does not have Host or Embedded Utilities.

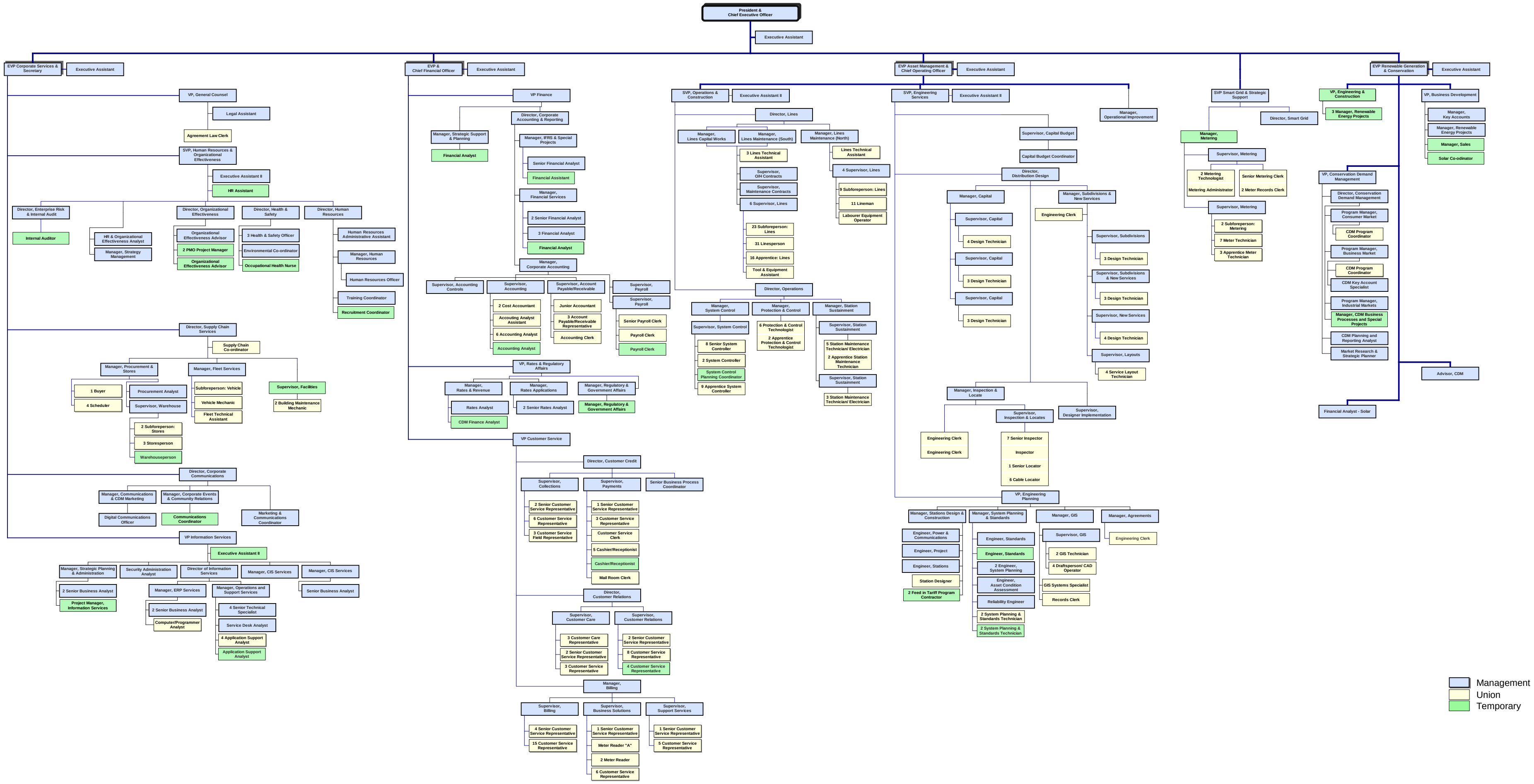
Schedule 7

UTILITY ORGANIZATION CHARTS

Note: **Renewable Generation and Conservation Division is not part of the revenue requirement in this application.**

PowerStream Inc. Organizational Chart

Confidential

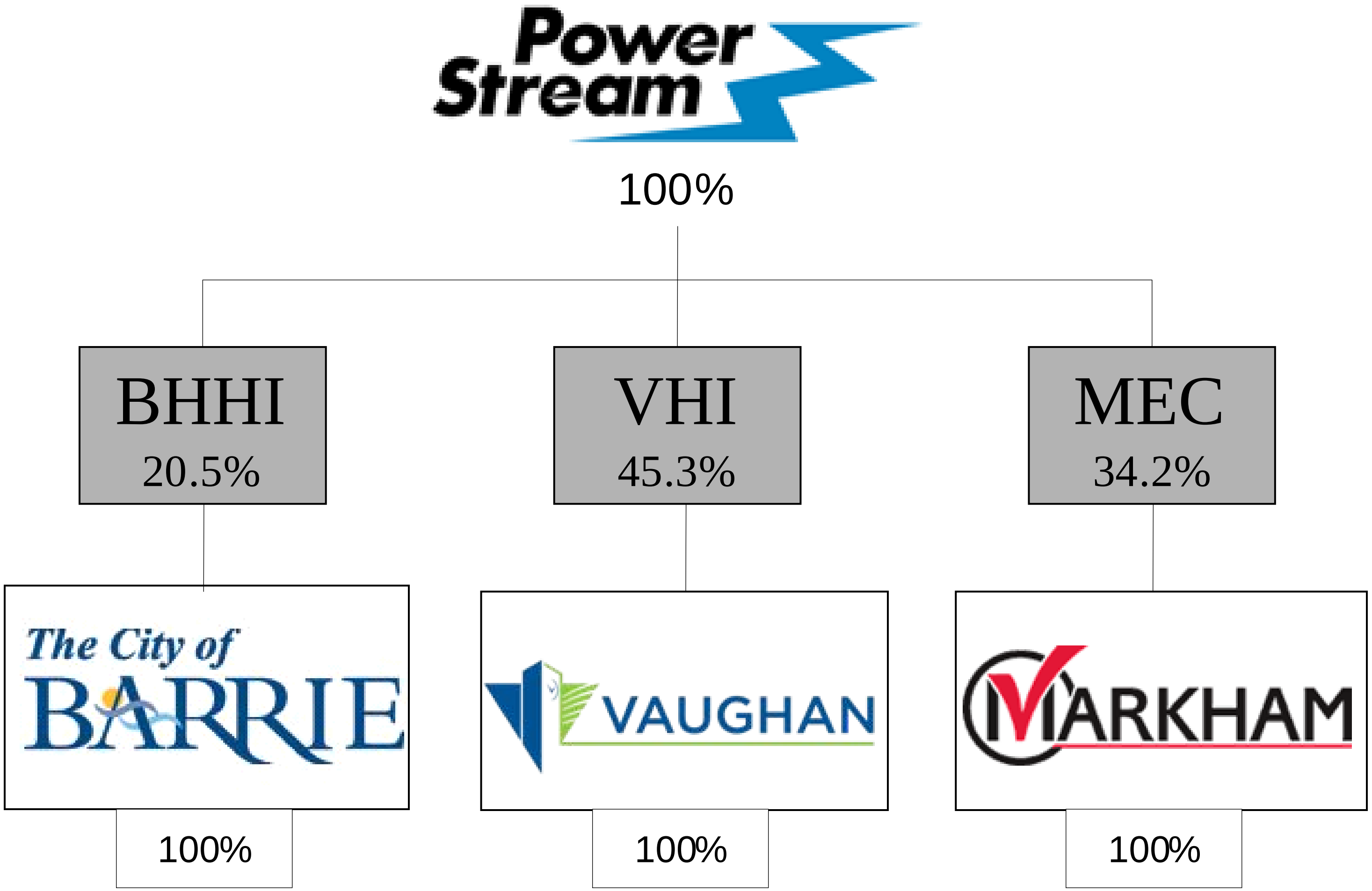


Last Printed December 31, 2011

Schedule 8

CORPORATE ENTITIES RELATIONSHIP CHART

Ownership Structure



Power Stream

100%

BHHI
20.5%

VHI
45.3%

MEC
34.2%

The City of BARRIE

100%

VAUGHAN

100%

MARKHAM

100%

Schedule 9

PLANNED CHANGES IN ORGANIZATIONAL / OPERATIONAL STRUCTURE

PowerStream Inc. is not planning changes in Organizational/Operational Structure.

Schedule 10

STATUS OF BOARD DIRECTIVES

PowerStream Inc. does not have any outstanding Board Directives.

Schedule 11

COMPANY POLICIES AND PROCEDURES ON ELECTRICITY SERVICES AND SERVICE CHARGES

Please refer to PowerStream Inc.'s website for the current version of the Conditions of Service www.powerstream.ca.

Schedule 12

LISTS OF PROPOSED CHANGES TO POLICIES AND PROCEDURES ON ELECTRICITY SERVICES AND SERVICE CHARGES

Please refer to PowerStream Inc.'s website for the updated list of changes to the Conditions of Service www.powerstream.ca.

Schedule 13

PROPOSED WITNESS PANELS AND CURRICULUM VITAE

PowerStream Inc. will assemble Witness Panels when necessary.

Schedule 14

FINANCIAL STATEMENTS BHDI – 2008 AUDITED

COPY

Barrie Hydro Distribution Inc.

Financial Statements

For the year ended December 31, 2008

Barrie Hydro Distribution Inc.
Financial Statements
For the year ended December 31, 2008

Contents

BDO

BDO Dunwoody LLP
Chartered Accountants
and Advisors

169 Dufferin Street South Units 13 &14
Alliston Ontario Canada L9R 1E6
Telephone: (705) 435-5585
Fax: (705) 435-5587

www.bdo.ca

Auditors' Report

To the Shareholder of
Barrie Hydro Distribution Inc.

We have audited the balance sheet of Barrie Hydro Distribution Inc. as at December 31, 2008 and the statements of operations and retained earnings (deficit) and cash flows for the year then ended. These financial statements are the responsibility of the corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the corporation as at December 31, 2008 and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Dunwoody LLP

Chartered Accountants, Licensed Public Accountants

Alliston, Ontario
March 5, 2009

Barrie Hydro Distribution Inc.
Balance Sheet

December 31	2008	2007
Assets		
Current		
Cash (Note 1)	$ 13,893,907	$ 4,282,292
Accounts receivable	11,438,974	10,285,080
Unbilled service revenue	13,533,221	14,574,342
Inventories	1,264,075	1,258,853
Prepaid expenses	810,729	599,377
Payments in lieu of corporate taxes receivable	1,866,487	-
	42,807,393	30,999,944
Property, plant and equipment (Note 2)	118,633,906	126,428,489
Construction in progress (Note 2)	1,837,214	3,665,584
Goodwill	9,554,075	9,554,075
Deferred charges and other long-term assets (Note 3)	675,280	852,801
	$173,507,868	$171,500,893
Liabilities and Shareholder's Equity		
Current		
Accounts payable and accrued liabilities	$ 19,744,879	$ 15,134,725
Construction deposits	1,455,792	5,920,312
Payments in lieu of corporate taxes payable	-	491,085
Due to related parties (Note 5)	1,564,343	1,476,376
Current portion of customer deposits	1,794,967	1,624,815
Current portion of capital lease obligation	-	64,892
Current portion of subdivision deposits	4,078,447	3,251,777
Current portion of long-term debt (Notes 5 and 8)	25,000,000	-
	53,638,428	27,963,982
Customer deposits	3,333,509	3,017,514
Regulatory liabilities (Note 4)	6,820,834	5,107,661
Other long-term liabilities (Note 6)	168,398	250,012
Employee future benefits (Note 7)	2,661,058	2,628,249
Long-term debt (Notes 5 and 8)	45,000,000	45,000,000
Subdivision deposit (net of refunds)	2,060,672	5,747,552
	113,682,899	89,714,970
Contingent liabilities (Note 11)		
Shareholder's equity		
Share capital (Note 12)	61,491,374	61,491,374
Retained earnings (deficit)	(1,666,405)	20,294,549
	59,824,969	81,785,923
	$173,507,868	$171,500,893

On behalf of the Board:

Director Michael Ramsay Director

ON BEHALF OF THE BOARD OF POWERSTREAM INC.

~~Director~~ CHAIR Frank Scarpitti ~~Director~~ VICE-CHAIR

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Barrie Hydro Distribution Inc.
Statement of Operations and Retained Earnings (Deficit)

For the year ended December 31	2008	2007
Service revenue		
Residential	**$ 18,972,611**	$ 19,212,933
Commercial (Note 5)	**11,339,803**	11,691,701
Street lighting	**213,170**	97,824
	30,525,584	31,002,458
Service revenue adjustments	**123,109**	112,705
	30,648,693	31,115,163
Cost of power revenue	**112,076,539**	112,788,540
	142,725,232	143,903,703
Cost of power	**112,076,539**	112,788,540
Distribution revenue	**30,648,693**	31,115,163
Other revenue		
Customers' forfeited discounts and late payment charges	**459,176**	579,945
Water and sewer billing collection services (Note 5)	**1,535,894**	1,507,749
Other revenue	**1,335,725**	1,465,484
	3,330,795	3,553,178
	33,979,488	34,668,341
Expenses		
Administration and general (Note 5)	**7,191,687**	6,595,425
Amortization	**9,327,765**	9,014,758
Interest on long-term debt (Note 5)	**2,912,508**	2,912,500
Other interest	**337,959**	354,178
Operation maintenance	**5,744,523**	4,495,543
	25,514,442	23,372,404
	8,465,046	11,295,937
Provision for payments in lieu of corporate income taxes and capital taxes (Note 14)	**(3,718,000)**	(5,450,000)
Net income for the year	**4,747,046**	5,845,937
Retained earnings, beginning of year	**20,294,549**	16,064,612
Dividends (Note 13)	**(26,708,000)**	(1,616,000)
Retained earnings (deficit), end of year	**$ (1,666,405)**	$ 20,294,549

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Barrie Hydro Distribution Inc.
Statement of Cash Flows

For the year ended December 31	2008	2007
Cash flows from operating activities		
Net income for the year	$ 4,747,046	$ 5,845,937
Adjustments for		
Amortization of property, plant and equipment	9,327,765	9,014,758
Loss on disposal of long-term investment	-	30,800
Gain on disposal of property, plant and equipment	(26,959)	(65,686)
Amortization of deferred charges and other long-term assets	177,521	205,886
	14,225,373	15,031,695
Changes in non-cash operating working capital		
Accounts receivable	(1,153,894)	1,429,855
Unbilled service revenue	1,041,121	(1,068,246)
Inventories	(5,222)	316,906
Prepaid expenses	(211,352)	103,505
Accounts payable and accrued liabilities	4,610,152	(398,204)
Construction deposits	387,685	(75,393)
Payments in lieu of corporate taxes payable	(2,357,572)	(478,079)
Due to related parties	87,967	497,855
	2,398,885	328,199
	16,624,258	15,359,894
Cash flows from investing activities		
Purchase of property, plant and equipment and construction in progress	(7,417,225)	(13,866,638)
Proceeds on sale of property, plant and equipment	26,959	65,686
Proceeds on disposition of long-term investment	-	40,985
	(7,390,266)	(13,759,967)
Cash flows from financing activities		
Increase in customer deposits	486,147	104,353
Increase in regulatory liabilities	1,713,173	3,449,892
Increase (decrease) in other long-term liabilities	(81,614)	5,898
Increase in employee future benefits	32,809	56,541
Repayment of capital lease obligations	(64,892)	(54,372)
Proceeds on long-term debt	25,000,000	-
Dividends paid	(26,708,000)	(3,066,000)
	377,623	496,312
Increase in cash during the year	9,611,615	2,096,239
Cash, beginning of year	4,282,292	2,186,053
Cash, end of year	$ 13,893,907	$ 4,282,292

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Barrie Hydro Distribution Inc.
Summary of Significant Accounting Policies

December 31, 2008

Nature of Business

The corporation was incorporated on October 19, 2000 under the laws of Ontario and is licensed by the Ontario Energy Board ("OEB") as an electricity distributor.

The principal activity of the corporation is to distribute electricity to the City of Barrie, and the towns of Bradford West Gwillimbury, Thornton, New Tecumseth and Penetanguishene.

The corporation is regulated by the OEB under authority of the Ontario Energy Board Act, 1998.

Basis of Accounting

The financial statements of Barrie Hydro Distribution Inc. are prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) and accounting policies provided by its regulator, the OEB, as contained in the Accounting Procedures Handbook for Electric Distribution Utilities ("AP Handbook"), issued under the authority of the Ontario Energy Board Act, 1998.

Due to the regulatory framework the timing of recognition of revenues and expenses and the measurement of certain assets and liabilities may differ from that otherwise expected under Canadian generally accepted accounting principles (GAAP) for non-rate regulated enterprises. Please refer to accounting policies for Spare Transformers and Meters, Post 1999 Contributed Capital, Regulatory Assets and Liabilities, and Payments in lieu of corporate income taxes and capital taxes.

The financial statements reflect the significant accounting policies summarized below.

Seasonality of Operations

The corporation's operations are seasonal. Electricity consumption is typically highest in the summer and winter months, July through September and January through March.

Regulation and Rate Setting

The corporation is required to follow regulations as set by the OEB. The OEB approves and sets rates for the transmission and distribution of electricity, ensures distribution companies fulfil their obligations to connect and service customers, and has the authority to provide rate protection for certain electricity customers.

The OEB sets rates on an annual basis with rates becoming effective on May 1st through April 30th of the following year. The regulation and monitoring of Ontario's Energy Sector is completed by the OEB through application of codes, rules and guidelines, the licensing of market participants, assisting firms with the management of regulatory requirements, monitoring and enforcing compliance and adjudication.

Inventories

Inventories consist of parts, supplies and materials held for future capital expansion or maintenance. Inventories are carried at the lower of average cost and net realizable value, with cost determined on an average cost basis net of a provision for obsolescence.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, overhead and engineering costs. Also included in property, plant and equipment is the costs of property, plant and equipment constructed by developers or customers and contributed to the corporation.

Amortization based on the estimated useful life of the asset is calculated as follows:

Land rights	- up to 50 years	straight-line basis
Buildings	- 30 to 60 years	straight-line basis
Distribution system	- 25 to 30 years	straight-line basis
General office equipment	- 10 years	straight-line basis
Computer equipment	- 5 years	straight-line basis
Computer software	- 3 years	straight-line basis
Rolling stock	- 5 to 8 years	straight-line basis
Other equipment	- 10 to 25 years	straight-line basis

Spare Transformers and Meters

Spare transformers and meters are held to back up plant in service and are expected to substitute for original distribution plant transformers and meters when these original plant assets are being repaired. Spare transformers and meters are treated as property, plant and equipment. These amounts are not being amortized until they are put into service.

Post 1999 Contributed Capital

Post 1999 contributed capital consists of third party contributions toward the cost of constructing distribution assets collected after January 1, 2000, and are recorded with property, plant and equipment as a contra account. Contributions are amortized at rates corresponding with the useful lives of the related property, plant and equipment. Canadian GAAP provides no specific guideline on the accounting for this type of contribution.

Construction in Progress

Construction in progress is comprised of the cost of assets not yet placed into service, assets under construction, and pre-construction activities related to projects expected to be completed. These amounts are not amortized. Upon completion of construction the amounts are transferred to property, plant and equipment and are amortized on a straight-line basis over the expected service life of the asset.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of book value of the net identifiable assets purchased.

Goodwill is not amortized but is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that the asset might be impaired.

When the carrying amount of goodwill exceeds the implied fair value of goodwill an impairment loss is recognized in an amount equal to the excess as a charge against the results of operations.

The corporation has determined that goodwill is not impaired.

Deferred Charges

Deferred financing charges represent the unamortized cost to issue long-term debt including fees paid to fix the interest rate of the issue. Amortization is provided on a straight-line basis, over the period to maturity of the related debt.

Other Long-Term Assets

Other long-term assets consist of amounts paid to Hydro One under capital cost recovery agreements. These costs are amortized over the life of the agreements, being 25 years, which represents the revenue stream for Hydro One.

Regulatory Assets and Liabilities

The corporation has adopted the CICA's Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Based on OEB regulations, certain costs and variance account balances are recorded as regulatory assets or regulatory liabilities and are reflected in the balance sheet until the OEB determines the manner and timing of their disposition.

Regulatory assets represent future revenues associated with certain costs, incurred in current or prior period(s), that are expected to be recovered through the rate setting process. Regulatory assets and liabilities can arise from differences in amounts billed to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the corporation in the wholesale market administered by the Independent Electricity System Operator "IESO" after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act and deferred in anticipation of their future recovery in electricity distribution service charges.

Customer Deposits

Customer deposits represent amounts collected from customers to guarantee the payment of energy bills. The customer deposits liability includes interest credited to customers' deposit accounts, with interest expense recorded to offset this amount. Deposits expected to be refunded to customers within one year are classified as a current liability.

Customer deposits also include prudential deposits from retailers.

Construction Deposits

Construction deposits represent maintenance deposits and deposits for recoverable work.

Pension Plan

The corporation offers a pension plan for its full-time employees through the Ontario Municipal Employee Retirement System ("OMERS"). OMERS is a multi-employer, contributory, public sector pension fund established for employees of municipalities, local boards and school boards in Ontario. Participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The corporation accounts for its participation in OMERS as a defined contribution plan and recognizes the expense related to this plan as contributions are made.

Post-employment Benefits

Employee future benefits other than pension provided by the corporation include medical and insurance benefits. These benefit plans provide benefits to certain employees when they are no longer providing active service.

Standards issued by The Canadian Institute of Chartered Accountants require the corporation to accrue for its obligations under other employee benefit plans and related costs.

The cost of post-employment benefits offered to employees are actuarially determined using the projected benefit method, prorated on service and based on assumptions that reflect management's best estimate. Under this method, the projected post-retirement benefit is deemed to be earned on pro-rata basis over the years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits.

The current service cost for the period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of the employees active at the date of the amendment.

The excess of the net actuarial gains (losses) over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility.

Subdivision Deposits

Subdivision deposits represent deposits received from developers based on the expected cost of capital for a new development. The OEB has stated that effective January 1, 2007 an economic evaluation is to be done at the beginning of the process and funds received will be based on developers' anticipated share of the cost based on the NPV calculation. A software developed by the EDA is used to determine the Economic Evaluation (Guidelines were created by OEB). The economic evaluation is a calculation of the net present value (NPV) of the expected revenue net of expected maintenance costs for the next 25 years. If the NPV calculation results in an amount less than the total cost to put the capital in place to service the subdivision the developer will pay the net difference as a deposit.

Revenue Recognition

Revenue from the sale and distribution of electricity is recognized on the accrual basis. The revenue includes cycles billed during the year plus an estimate for unbilled revenue. The unbilled revenue is calculated by estimating the consumption of electricity by customers since their last meter reading date to December 31, 2008. Actual results could differ from estimates made of electricity usage.

Other revenues, which include revenues from pole attachment, customer demand work, and other miscellaneous revenues are recognized at the time the service is provided.

Payment in Lieu of Corporate Income Taxes and Capital Taxes

The corporation is a municipal electricity utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a MEU the corporation is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Each taxation year, the corporation is required to make payments in lieu of corporate income taxes and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated based on the rules for computing taxable income and taxable capital outlined in Income Tax Act (Canada) and the Corporations Tax Act (Ontario) with taking into account any modifications made by the Electricity Act, 1998, and related regulations.

The corporation provides for payments in lieu of corporate income taxes and capital taxes related to its regulated business using the taxes payable method as permitted by the CICA and the OEB.

Under this method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable or receivable, it is expected that they will be reflected in the rates approved by the OEB at that point in time.

Use of Estimates and Measurement Uncertainty

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes as well as the disclosure of contingent assets and liabilities at the financial statement date.

Accounts receivable, unbilled service revenue, regulatory assets, regulatory liabilities and employee future benefits are reported based on amounts expected to be recovered or incurred and an appropriate allowance has been provided based on management's estimate of unrecoverable amounts.

Due to uncertainty involved in making such estimates, actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the accounting policies.

Financial Instruments

The corporation classifies its financial instruments into one of the following categories:

Held-for-Trading
Held-for-trading is comprised of cash. This instrument is carried in the balance sheet at fair value with changes in fair value recognized in the income statement. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Loans and Receivables
Loans and receivables are comprised of accounts receivable and unbilled service revenue. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest rate method, less any provision for impairment.

Other Financial Liabilities
Other financial liabilities are comprised of accounts payable and accrued liabilities, construction deposits, customer deposits, due to related parties, subdivision deposits, obligations under capital leases, long-term debt and other long-term liabilities. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are netted against the amount initially recognized.

Changes in Accounting Policies

Effective January 1, 2008, the corporation was required to adopt the new accounting framework on capital disclosures, inventories and financial instruments.

Capital Disclosures
CICA Handbook Section 1535, Capital Disclosures, requires disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital and whether the entity has complied with any capital requirements and, .if it has not complied, the consequences of such non-compliance. Effective January 1, 2008, the corporation has made additional note disclosure.

Financial Instruments – Disclosures and Presentation
CICA Handbook Section 3862, Financial Instruments - Disclosure, increases the disclosures currently required to enable users to evaluate the significance of financial instruments for an entity's financial position and performance, including disclosures about fair value. CICA Handbook Section 3863, Financial Instruments – Presentation, replaces the existing requirements on the presentation of financial instruments, which have been carried forward unchanged. The corporation has provided the additional note disclosures and presentations within its financial statements.

Inventories
The CICA has issued Section 3031, Inventories, which provides guidance on determining cost as well as other recognition, measurement, disclosure and presentation issues related to inventories. The standard includes guidance on the treatment of excess capacities, inventory valuation and write-downs and additional elements to be considered in measuring inventory costs. The corporation has adopted the new standards with no significant impact.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

Financial Statement Concepts
CICA Handbook Section 1000, Financial Statement Concepts, has been amended to focus on the capitalization of costs that truly meet the definition of an asset and de-emphasizes the matching principle. The revised requirements are effective for annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. The corporation is currently evaluating the impact of the adoption of this change on the disclosure within its financial statements.

Rate Regulated Operations
Effective January 1, 2009, the temporary exemption from CICA Section 1100, Generally Accepted Accounting Principles, which permits the recognition and measurement of assets and liabilities arising from rate regulation, will be withdrawn. In addition, Section 3465, Income Taxes, was amended to require the recognition of future income tax liabilities and assets. As a result of these changes, the corporation will be required to recognize future income tax liabilities and assets instead of using the taxes payable method, and will record an offsetting adjustment to regulatory assets and liabilities. These changes will be applied prospectively January 1, 2009.

Currently, the corporation uses the taxes payable method of accounting for income taxes. Had the corporation applied the new standards at December 31, 2008, the effect would be an increase in future income tax assets of $13,874,000, including an amount associated with income taxes that will become payable on future revenues as they are collected from customers when the tax timing differences reverse. There would also be a corresponding increase in regulatory liabilities of $13,874,000. There is no impact to opening retained earnings expected upon the adoption of these amendments.

International Financial Reporting Standards
The Canadian Accounting Standards Board ("AcSB") confirmed that the adoption of International Financial Reporting Standards ("IFRS") would be effective for interim and annual periods beginning on or after January 1, 2011 for Canadian publicly accountable profit-oriented enterprises. IFRS will replace Canada's current GAAP for these enterprises. Comparative IFRS information for the previous fiscal year will also have to be reported. These new standards will be effective in the fiscal year ended December 31, 2011.

The corporation is currently assessing the potential impact of IFRS to the financial statements. The financial statements as disclosed under current GAAP may be significantly different when presented in accordance with IFRS.

1. Cash

The corporation's bank accounts are held at one chartered bank. The corporation received interest on the bank accounts at prime less 1.75%.

The corporation also has an available credit facility of $10,000,000 by way of prime rate based loans, bankers acceptances, letters of credit and stand-by letters of guarantee. At the year end date, the credit facility has not been utilized.

The corporation also has a demand loan of $25,000,000 by way of prime rate based loans, bankers acceptances, letters of credit and stand-by letters of guarantee. This facility was fully utilized at year end (see Note 8).

---

2. Property, Plant and Equipment and Construction in Progress

	2008		2007	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Land	**$ 1,853,761**	**$ -**	$ 1,856,641	$ -
Land rights	**75,274**	**60,599**	75,274	59,263
Buildings	**17,511,562**	**4,769,999**	17,388,836	4,423,574
Distribution system	**222,955,192**	**89,580,604**	206,144,977	81,455,353
Spare meters and transformers	**1,876,349**	**-**	1,857,004	-
General office equipment	**1,344,581**	**1,122,810**	1,311,451	1,078,843
Computer equipment	**5,501,805**	**4,550,006**	5,427,331	4,021,133
Computer software	**3,377,813**	**2,986,858**	3,261,266	2,441,448
Rolling stock	**5,007,074**	**3,530,746**	4,532,773	2,945,988
Other equipment	**5,563,083**	**2,821,335**	5,453,387	2,587,382
Post 1999 contributed capital	**(41,628,320)**	**(4,618,689)**	(25,399,222)	(3,531,755)
	$223,438,174	**$104,804,268**	$221,909,718	$ 95,481,229
Net Book Value		**$118,633,906**		$126,428,489

	2008	2007
Construction in progress	**$ 1,837,214**	$ 3,665,584

During the year the corporation acquired $7,417,225 (2007 - $13,866,638) of property, plant and equipment and construction in progress using cash.

3. Deferred Charges and Other Long-term Assets

	2008	2007
Financing charges	**$ -**	$ 145,920
Deferred assets - Hydro One	**675,280**	706,881
	$ 675,280	$ 852,801

In 2006 the corporation entered into agreements with Hydro One for the right to deliver electricity through Hydro One owned lines and equipment. The total costs per the agreements were $765,887. The asset is being amortized over the term of the agreement of 25 years.

Amortization of financing fees in the amount of $145,920 (2007 - $161,840), and deferred assets - Hydro One in the amount of $31,601 (2007 - $31,602) are included in the Statement of Operations and Retained Earnings (Deficit).

4. Regulatory Assets/(Liabilities)

Regulatory assets/(liabilities) arise as a result of the rate-making process and consist of the following:

	2008	2007
Settlement variance accounts	**$ (5,361,485)**	$ (4,613,795)
Smart meters deferred revenue	**(498,251)**	(321,499)
Carrying charges (recovery)	**(421,977)**	(172,367)
Recovery of regulatory assets	**(539,121)**	-
Net Regulatory Liabilities	**$ (6,820,834)**	$ (5,107,661)

4. Regulatory Assets/(Liabilities) continued

Regulatory balances are comprised as follows:

(i) Settlement Variances:

Settlement variances represent the differences between amounts charged by the corporation to its customers based on regulated rates and the corresponding cost incurred by the corporation in the wholesale market administered by the IESO. Under the OEB's direction, the corporation has deferred the settlement variances that have occurred since May 1, 2002. Accordingly, the corporation has deferred these recoveries in accordance with the AP Handbook.

The OEB allows the variances to be deferred which would normally be recorded as revenue for unregulated businesses under Canadian GAAP. In absence of rate regulation, revenues in 2008 would have been $1,713,173 higher (2007 - $3,449,892 higher). The deferred balance for unapproved settlement variances continues to be calculated and carrying charges are accumulated in accordance with the OEB's direction. The manner and timing of disposition of the variance has not been determined by the OEB.

(ii) Carrying Charges

Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. In the absence of rate regulation, other revenues would have been higher by $249,610 (2007 - $154,723 higher).

(iii) Recovery of Regulatory Assets

In a letter dated December 19, 2003, the Minister of Energy granted approval for distributors to make application to the OEB with regard to rate recovery of certain distribution regulatory assets whose inclusion in rates was delayed by the Electricity Pricing, Conservation and Supply Act, 2002 (Electric Pricing, Conservation and Supply Act). As a result of the corporation's distribution rate application dated January 22, 2004, the distribution regulatory assets that accumulated up to December 31, 2002 are expected to be recovered over a four-year period, effective March 1, 2004 with an implementation date for consumption of April 1, 2004.

The rate application for 2006, approved by the OEB, included the recovery of regulatory assets accumulated to December 31, 2004 plus projected interest on these balances up to April 30, 2006. This second phase of recovery is for a two year period with rates effective May 1, 2006. As of May 1, 2008 these amounts were removed from rates. An over collection of these amounts totaling $539,121 will be disposed based on future OEB rate applications.

The rate application for 2008, approved by the OEB, included the recovery of regulatory assets accumulated to December 31, 2006 plus projected interest on these balances up to April 30, 2008. Rates to recover these amounts were effective May 1, 2008 and will be in effect over a three year period.

4. Regulatory Assets and Liabilities continued

(iv) Additional Information

Included in regulatory assets/(liabilities) is $265,526 to reflect amounts owing to Hydro One with respect to low voltage charges relating to the time period beginning May 1, 2002 ending December 31, 2003. Also included in regulatory assets/(liabilities) is $123,248 representing an estimate of the low voltage charges for the period beginning January 1, 2004 ending April 30, 2006. These amounts were included in the rate submission for 2006 and were recovered by December 31, 2008.

(v) Smart Meter Deferred Revenue

During 2006, the OEB adopted recommendations on smart meters with regard to cost recovery during the phase-in period of this equipment. The OEB stated that given the increased need for electricity and the importance of conservation, specific funding for smart meters should be included in 2006 rates by all Ontario electric LDC. Management intends to install the smart meters and the supporting infrastructure by the end of 2010. Variance accounts were established to track revenues collected with respect to smart meters and associated costs of the initiatives. In the absence of rate regulation, net income would have been higher in 2008 by $176,752 (2007 - $211,259).

(vi) Fair Value of Regulatory Assets and Regulatory Liabilities

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the regulator in determining the asset's treatment for rate setting purposes.

Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

5. Related Party Transactions

The Corporation of the City of Barrie is the 100% owner of Barrie Hydro Holdings Inc. which is the parent company of Barrie Hydro Distribution Inc. and Barrie Hydro Energy Services Inc.

At the end of the year, the amounts due to (from) related parties are as follows:

	2008	2007
The Corporation of the City of Barrie	**$ 1,794,618**	$ 888,283
Barrie Hydro Energy Services Inc.	**(268,082)**	(14,526)
Barrie Hydro Holdings Inc.	**37,807**	602,619
	$ 1,564,343	$ 1,476,376

5. Related Party Transactions - continued

These balances are interest-free, unsecured, payable on demand and have arisen from the sales of product and provision of services referred to below.

The corporation is also indebted to the Corporation of the City of Barrie for a $20,000,000 (2007 - $20,000,000) promissory note (see Note 8).

The following are the corporation's related party transactions for the year:

During the year, the corporation billed electricity and services to the Corporation of the City of Barrie in the amount of $1,653,844 (2007 - $1,549,334).

During the year, the corporation billed for cost recoveries of various projects to the Corporation of the City of Barrie in the amount of $3,018,742 (2007 - $1,009,061).

During the year, the corporation paid municipal taxes to the Corporation of the City of Barrie in the amount of $308,752 (2007 - $307,605). Municipal taxes are included in administration and general on the Statement of Operations and Retained Earnings.

During the year, the corporation was charged interest expense of $1,300,000 (2007 - $1,300,000) by the Corporation of the City of Barrie.

During the year, the corporation billed Barrie Hydro Energy Services Inc. an amount of $1,535,894 (2007 - $1,507,749) for billing, collection and water heater services.

These transactions are in the normal course of operations and are measured at exchange value.

6. Other Long-term Liabilities

	2008	2007
Developer deposits	**$ 168,398**	$ 111,207
Collateral funds	**-**	138,805
	$ 168,398	$ 250,012

Collateral funds represent amounts collected in lieu of development charges. Use of these funds is limited to specific terms set out in an agreement. The above balance includes accrued interest calculated annually at a rate equal to the bank rate obtained by the corporation for its deposits. At year end, these projects were finalized.

7. Employee Future Benefits

Barrie Hydro Distribution Inc. pays certain medical and insurance benefits under an unfunded defined benefit plan on behalf of its retired employees. The corporation recognizes these post-retirement costs in the period in which the employees render the services.

An actuarial report was performed and dated February 28, 2008. The accrued benefit obligation and current service cost were determined using the projected method, pro-rated on service. The actuarial valuation was performed on the post-retirement obligations sponsored by Barrie Hydro Distribution Inc. as at January 1, 2007, with figures extrapolated to December 31, 2008.

Information about Barrie Hydro Distribution Inc.'s defined benefit plan is as follows:

	2008	2007
Accrued benefit obligation, opening balance	**$ 2,628,249**	$ 2,571,708
Current service cost	**95,280**	90,527
Interest cost	**137,730**	135,640
Actuarial losses	**-**	12,375
Benefits paid	**(200,201)**	(182,001)
Projected accrued benefit obligation	**$ 2,661,058**	$ 2,628,249
Additional Disclosures:		
Unamortized actuarial gain (loss)	**$ -**	$ -

Sensitivity Analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans.

The effect of a one-percentage point increase in assumed health care cost trend rates on 2008:

Accrued benefit obligation, end of period	**$ 2,768,058**	$ 2,735,249
Increase in net period benefit cost	**$ 107,000**	$ 107,000

The effect of a one-percentage point decrease in assumed health care cost trend rates on 2008:

Accrued benefit obligation, end of period	**$ 2,485,058**	$ 2,452,249
Decrease in net period benefit cost	**$ 176,000**	$ 176,000

7. Employee Future Benefits - continued

The main actuarial assumptions employed for the valuations are as follows:

(a) General inflation:

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% in 2008 (2007 - 2.0%).

(b) Interest (discount) rate:

The obligation as at December 31, 2008, representing the present value of future liabilities was determined using a discount rate of 5.25% (2007 - 5.25%). This corresponds to the assumed CPI rate plus an assumed real rate of return of 3.25% (2007 - 3.25%).

(c) Salary levels:

Future general salary and wage levels were assumed to increase at 3.3% (2007 - 3.3%) per annum.

(d) Medical costs:

Medical costs were assumed to increase at the CPI rate plus a further increase of 7.0% (2007 - 8.0%). This rate will be graded down by 1% per year to 3.0% in 2012 and thereafter.

(e) Dental costs:

Dental costs were assumed to increase at the CPI rate plus a further increase of 3.0% (2007 - 3.0%).

8. Long-term Debt

	2008	2007
Demand loan by way of bankers acceptance, prime rate based loans, letters of credit and stand-by letters letters of guarantee	**$ 25,000,000**	$ -
6.45% EDFIN bond, with interest only payable in arrears semi-annually on August 15 and February 15, maturing August 15, 2012	**25,000,000**	25,000,000
6.5% unsecured promissory note, payable to the Corporation of the City of Barrie with interest only payable December 31 maturing May 31, 2024	**20,000,000**	20,000,000
	70,000,000	45,000,000
Less: current portion of long-term debt	**25,000,000**	-
	$ 45,000,000	$ 45,000,000

(a) EDFIN bond:

In August of 2002 the corporation refinanced part of the existing debt with a 10-year bond issue for $25,000,000. The corporation was one of five local distribution companies ("LDCs") that participated in the Electricity Distributors Finance Corporation ("EDFIN") 10-year Bond issue (Series 2002-1) that was offered on a private placement. EDFIN is a special purpose corporation managed by MEARIE Management Inc., for the purpose of providing LDCs with efficient access to the debt capital markets. Each LDC has executed a debenture which is a direct and unsecured obligation of the LDC. The LDCs' obligations will be several and not joint, and each LDC will be liable for its own obligation and not that of any other LDC. Due to a change in structure of the participating corporations, there are now three LDCs with EDFIN bonds.

(b) Promissory note:

The promissory note is repayable 90 days following demand by the City, with subordination to the EDFIN bond and the bank demand loan. This note has been classified as long-term as it is not the intent of the City to demand repayment within the next year.

9. Pension Agreement

The corporation makes contributions to the OMERS, which is a multi-employer plan, on behalf of members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to more than 380,000 active and retired members and approximately 910 employers.

Each year an independent actuary determines the funding status of OMERS by comparing the actuarial value of the invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the plan was conducted at December 31, 2008. The results of this valuation disclosed total actuarial liabilities of $50,080 million (2007 - $46,830 million) in respect of benefits accrued for service with actuarial assets of $49,801 million (2007 - $46,912 million) indicating an actuarial deficit of $279 million (2007 - surplus of $82 million). As OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipalities, their public business enterprises and their employees. As a result, the corporation does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for 2008 were 6.5% for employees earning up to $44,900 and 9.6% thereafter. The amount contributed to OMERS for 2008 was $519,629 (2007 - $491,902).

10. Liability Insurance

The corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2008, the corporation has not been made aware of any assessments for losses.

11. Contingent Liabilities

i) Griffith et al. v. Toronto Hydro-Electric Commission et al.

This action has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

On February 4, 2008, the OEB, in response to an application filed by Enbridge, ruled that all of Enbridge's costs related to settlements of the class action lawsuits, including legal costs, settlement costs and interest, are recoverable from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas.

The corporation collected total late payment penalties of approximately $4,569,000 from April 30, 1994 to May 1, 2001. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made, and as such, no accrual for any potential liability has been recorded in the financial statements.

(ii) The corporation has other claims outstanding which in managements' opinion will be covered by insurance.

iii) The corporation has posted a letter of credit for $100,000 maturing on October 31, 2009.

12. Share Capital

The corporation is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares.

The issued share capital is as follows:

	2008	2007
1,000 Common shares	**$ 61,491,374**	$ 61,491,374

13. Dividends

During 2004 a dividend policy was adopted by the Board of Directors of Barrie Hydro Holdings Inc. stating that the amount of dividends payable by the corporation to the Corporation of the City of Barrie is equal to 30% of the corporation's audited net income after extraordinary items for the year.

Dividends totaling $1,008,000 were paid during the first three quarters of 2008 fiscal year. A special dividend of $25,700,000 was also declared and paid in the last quarter of 2008. Any final dividend for 2008 will be the responsibility of the amalgamated entity (see Note 18). In 2007, dividend payments totaled $3,066,000, which included the 2006 accrued dividend of $1,450,000.

14. Payments in Lieu of Corporate Income Taxes, Capital Taxes and Future Income Taxes

(a) Payments in lieu of corporate income taxes ("PILs") and capital taxes

The corporation's provision for PILs is calculated as follows:

	2008	2007
Income before provision for PILs	**$ 8,465,046**	$ 11,295,937
Finance costs and employee benefits	**210,331**	202,461
Regulatory liabilities added back for tax purposes	**1,713,173**	3,449,892
Capital tax included in tax provision	**(288,686)**	(362,455)
Capital cost allowance less than amortization expense	**305,414**	246,443
Other items	**412,748**	(101,607)
Income for tax purposes	**10,818,026**	14,730,671
Statutory Canadian federal and provincial tax rate	**33.50%**	36.12%
Provision for PILs	**3,624,039**	5,320,718
Capital tax	**288,686**	362,455
Other (recovery)	**(194,725)**	(233,173)
Total provision	**$ 3,718,000**	$ 5,450,000

(b) Future Taxes

Future income taxes have not been recognized in these financial statements. Section 3465 of the CICA Handbook does not require rate regulated enterprises to recognize future income taxes if future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers.

Significant components of the corporation's future taxes are as follows:

	2008	2007
Employee future benefits	**$ 891,000**	$ 880,000
Regulatory liabilities	**2,285,000**	1,711,000
Property, plant and equipment	**10,698,000**	7,990,000
Net future income tax asset	**$ 13,874,000**	$ 10,581,000

A future income tax recovery of $3,293,000 (2007 - recovery of $277,000) has not been recognized in the provision.

15. Capital Disclosures

The corporation's main objectives when managing its capital are to:

- maintain a financial position suitable for supporting the company's operations and growth strategies
- provide an adequate return to its shareholder
- ensure compliance with covenants related to its credit facilities; and
- align its capital structure for regulated activities with the debt to equity structure recommended by the OEB, which is 60% debt and 40% equity by 2010.

The corporation defines capital as the aggregate of shareholder's equity and long-term debt. This definition has remained unchanged from December 31, 2007. As at December 31, 2008, shareholder's equity amounts to $59,824,969 (2007 - $81,785,923) and long-term debt amounts to $70,000,000 (2007 - $45,000,000). The company's capital structure as at December 31, 2008 is 54% debt and 46% equity (2007 - 35% debt and 65% equity). During the year, the company paid a special dividend of $25,700,000, financed through bank debt, to more closely align their debt equity structure as recommended by the OEB.

The corporation has externally imposed capital requirements in the form of a credit facility agreement that contains various covenants (Note 1). The corporation's credit facility limits the debt to capitalization ratio to 55%. as at December 31, 2008 the debt to capitalization ratio was 42%. The corporation was in compliance with all credit facility agreements covenants as at December 31, 2008.

16. Financial Instruments

The corporation is not exposed to significant interest rate risk as a result of the short-term maturity of its monetary current assets and current liabilities.

Financial assets held by the corporation expose it to credit risk. As at December 31, 2008 there were no significant concentrations of credit risk with respect to any class of financial assets.

The carrying value of cash, accounts receivable, unbilled service revenue and accounts payable and accrued liabilities approximate their fair value due to the immediate or short-term maturity of these financial instruments.

At December 31, 2008, the fair value of the EDFIN bond payable is approximately $26,100,000 (2007 - $26,400,000) and the fair value of the uncommitted demand loan is approximately $25,000,000. The fair value has been calculated by discounting the future cash flow of the respective long-term debt at the estimated yield to maturity of similar debt instruments (Note 8).

The fair values of the corporation's related party note payable to the Corporation of the City of Barrie and other amounts due to/from related parties are not determinable due to their related party nature and terms.

The corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The corporation's objective is to ensure sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest expense. The corporation has access to credit facilities and monitors cash balances daily to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

The corporation has not entered into any hedging or derivative financial instruments. The corporation also has limited exposure to changing values of foreign currencies.

17. Statement of Cash Flows

	2008	2007
Interest paid	**$ 3,250,467**	$ 3,266,678
Payment in lieu of corporate income taxes, Part 1.3 and capital taxes paid (net of taxes received)	**$ 6,239,638**	$ 5,928,079

18. Subsequent Event

On January 1, 2009, the Corporation of the City of Barrie, through its wholly owned subsidiary Barrie Hydro Holdings Inc; the City of Vaughan through its wholly owned subsidiary Vaughan Holdings Inc.; the Town of Markham through its wholly owned subsidiary Markham Enterprises Corporation; agreed to amalgamate Barrie Hydro Distribution Inc. and PowerStream Inc. and continue as a Corporation amalgamated under the laws of Ontario. The amalgamated Corporation retained the PowerStream Inc. corporate name. The amalgamated corporation issued common shares to Vaughan Holdings Inc., Markham Enterprises Corporation and Barrie Hydro Holdings Inc. in exchange for each company's issued and outstanding shares in the Corporation. The number of shares issued to each shareholder are as follows:

	Number of shares
Vaughan Holdings Inc.	**45,315**
Markham Enterprises Corporation	**34,185**
Barrie Hydro Holdings Inc.	**20,500**

19. Comparative Amounts

Certain comparative figures presented in the financial statements have been restated to conform to the current year's financial statement presentation.

Schedule 15

FINANCIAL STATEMENTS – 2010 AUDITED

Financial statements of

PowerStream Inc.

December 31, 2010

PowerStream Inc.

December 31, 2010

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Independent Auditor's Report

To the Shareholders of PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2010, and the statements of earnings and comprehensive income and retained earnings and of cash flows for the year the ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit.
We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement to the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2010, and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
April 27, 2011

PowerStream Inc.

Balance sheet
as at December 31, 2010

(In thousands of dollars)

	2010	2009
	$	$
Assets		
Current assets		
Cash	8,568	42,612
Accounts receivable, net of allowance for doubtful accounts (Note 18(c))	69,366	73,633
Unbilled revenue	92,207	88,160
Income taxes recoverable	-	1,525
Inventories (Note 4)	3,050	3,869
Prepaids and other	2,718	2,581
	175,909	212,380
Property, plant and equipment, net (Note 5)	642,059	601,764
Regulatory assets (Note 7(a))	31,961	26,433
Deferred charges, net of amortization of $63 (2009 - $31)	612	644
Intangibles, net (Note 6)	4,180	3,614
Future income tax assets (Note 20(b))	53,313	61,665
Goodwill	42,543	42,543
	950,577	949,043
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities (Note 8)	105,339	110,405
Current portion of customers' deposits	1,478	1,000
Income taxes payable	6,622	5,034
Due to related parties (Note 9)	12,214	12,049
Short-term debt (Note 10(a))	40,000	40,000
Infrastructure Ontario Financing (Note 10(b))	827	-
Current portion of liability for subdivision development	4,138	3,375
Current portion of capital lease obligation (Note 16)	259	-
	170,877	171,863
Long-term liabilities		
Bank term loan (Note 11(a))	50,000	50,000
Debentures payable (Note 11(b))	123,765	123,091
Notes payable (Note 11(c))	182,430	182,430
Regulatory liabilities (Note 7(b))	68,314	91,140
Customers' deposits	12,071	16,726
Employee future benefits (Note 12)	14,007	12,036
Liability for subdivision development	1,232	4,917
Construction deposits	23,364	23,172
Capital lease obligation (Note 16)	17,679	-
Future Income tax liabilities (Note 20(c))	61	-
Other liabilities	160	5,421
	493,083	508,933
Shareholders' equity		
Share capital (Note 14)	249,618	247,183
Retained earnings	36,999	21,064
	286,617	268,247
	950,577	949,043

Approved on behalf of the Board

_______________ Director

_______________ Director

See accompanying notes to the financial statements.

PowerStream Inc.

Statement of earnings and comprehensive income and retained earnings year ended December 31, 2010

(In thousands of dollars)

	2010	2009
	$	$
Revenue		
Sale of energy	**691,318**	621,719
Distribution revenue	**155,841**	146,076
Other revenue	**9,229**	9,889
Total revenue	**856,388**	777,684
Cost of power purchased	**691,318**	621,719
	165,070	155,965
Operating expenses	**59,746**	62,601
Earnings before amortization, interest and income taxes	**105,324**	93,364
Depreciation of property, plant and equipment and intangibles (net of $2,803 (2009 - $2,582) charged to other accounts)	**46,255**	42,125
Net interest expense (Note 22)	**22,014**	21,614
Income before income taxes	**37,055**	29,625
Income tax expense (Note 20(a))	**10,588**	8,561
Net earnings and comprehensive income for the year	**26,467**	21,064
Retained earnings, beginning of year	**21,064**	-
Dividends (Note 14)	**(10,532)**	-
Retained earnings, end of year	**36,999**	21,064

See accompanying notes to the financial statements.

PowerStream Inc.

Statement of cash flows
year ended December 31, 2010

(In thousands of dollars)

	2010	2009
	$	$
Operating activities		
Net earnings for the year	26,467	21,064
Adjustments to determine cash provided by operating activities		
Depreciation of property, plant and equipment	46,675	42,006
Accretion of debentures payable	674	629
Amortization of intangibles	2,383	2,701
Amortization of deferred charges	32	31
Employee future benefits	1,971	923
Future income taxes	8,413	6,759
Decrease in regulatory assets/liabilities	(28,354)	(23,280)
Loss (gain) on disposal of property, plant and equipment	533	(218)
Net change in non-cash operating working capital (Note 21)	(2,714)	(23,328)
	56,080	27,287
Financing activities		
Decrease in liability for subdivisions development	(2,922)	(3,164)
(Decrease) increase in long-term customers' deposits	(4,655)	1,223
Decrease in other liabilities	(5,261)	(47)
Obligations to predecessor shareholders (Note 14)	-	(31,082)
Dividends paid (Note 14)	(10,532)	-
Increase in short-term debt	-	15,000
Increase in construction deposits	192	23,172
Decrease in principal on capital lease obligation	(342)	-
Increase in Infrastructure Ontario Financing	827	-
	(22,693)	5,102
Investing activities		
Proceeds on disposal of property, plant and equipment	140	248
Purchase of intangibles	(2,949)	(6,314)
Purchase of property, plant and equipment, net of contribution of capital construction	(67,057)	(67,419)
Proceeds from the issuance of Class A common shares	2,435	-
	(67,431)	(73,485)
Decrease in cash during the year	(34,044)	(41,096)
Cash, beginning of year	42,612	83,708
Cash, end of year	8,568	42,612
Supplementary cash flow information		
Cash paid during the year for:		
Interest	22,619	21,298
Payments in lieu of corporate income taxes	9,247	10,026
Acquisition of property, plant and equipment financed by capital lease	18,280	-

See accompanying notes to the financial statements.

1. Description of the business

PowerStream Inc. (the "Corporation") was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is owned by the Corporation of the City of Vaughan (the "City of Vaughan"), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the Town of Markham (the "Town of Markham"), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the "City of Barrie"), through its wholly owned subsidiary, Barrie Hydro Holdings Inc.

The principal activity of the Corporation is to distribute electricity in the service area of Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under licenses issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation has commenced operations of a solar generation business, in 2010, as permitted by these changes.

2. Significant accounting policies

The Corporation's financial statements are the representations of management prepared in accordance with Canadian Generally Accepted Accounting Principles ("CGAAP") and accounting policies provided by its regulator, the OEB, as contained in the Accounting Procedures Handbook for Electric Distribution Utilities, issued under the authority of the Ontario Energy Board Act, 1998.

The financial statements reflect the following significant accounting policies:

(a) Rate setting

The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

As the Corporation is regulated by the OEB, the timing of recognition and measurement of assets and liabilities arising from rate regulation in these financial statements may differ from what is otherwise expected under CGAAP for non-rate regulated enterprises. The Corporation has determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under CGAAP and this recognition is consistent with the U.S. Statement of Financial Accounting Standards No. 71 - "Accounting for the Effects of Certain Types of Regulation".

2. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the Independent Electricity System Operator ("IESO").

(ii) Other revenue

Other revenue related to the sale of other services is recognized as services are rendered. Contract revenue is accounted for using the percentage of completion method, whereby revenue is recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident.

(c) Financial instruments

The Corporation has made the following balance sheet classifications in connection with its financial assets and financial liabilities:

(i) Cash is classified as financial assets "Held-for-Trading" and is measured at fair value.

(ii) Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost using the effective interest method.

(iii) Accounts payable, accrued liabilities, amounts due to related parties, short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable, notes payable and customers' deposits are classified as "Other Financial Liabilities" and are measured at amortized cost using the effective interest method.

Financial assets and liabilities are initially recorded at fair value. The fair value is the amount of the consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act. Transaction costs are netted against the proceeds of financial instruments classified as "Other Financial Liabilities" and are considered when determining the effective interest rate for the discounted cash flows. Subsequent measurement depends on how each financial instrument is classified on the balance sheet.

2. Significant accounting policies (continued)

(c) Financial instruments (continued)

The Corporation has classified fair value measurements using a fair value hierarchy that reflects three levels of inputs used in making the fair value measurements. The fair value hierarchy has the following levels:

(i) Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities;

(ii) Level 2: Observable inputs other than quoted prices included in Level 1, such as derived prices for similar assets and liabilities; or quoted prices in inactive markets; and

(iii) Level 3: Unobservable inputs for the assets or liabilities that are not based on observable market data.

(d) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, is stated at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis. Any impairment losses taken on inventories are reversed if and when net realizable value subsequently recovers. Major spare parts and standby equipment are recorded as part of property, plant and equipment and depreciated once they are put into use.

(e) Property, plant and equipment and depreciation

Property, plant and equipment ("PP&E") is recorded at cost and includes contracted services, materials, labour, engineering costs, interest and overheads. Certain PP&E assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. Such contributions, whether in cash or in-kind, are offset against the related PP&E asset cost. Contributions in-kind are valued at their fair value at the date of their contribution.

When identifiable assets, such as buildings, distribution station equipment, equipment and furniture are retired or otherwise disposed of, their original cost and related accumulated depreciation are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period.

Depreciation of PP&E is provided for on a straight-line basis over the estimated service life of the assets. Depreciation of contributions from developers or customers is depreciated at the rates corresponding with the useful lives of the related PP&E. The estimated service lives of the various assets used in calculating depreciation are summarized below:

Buildings	10 to 50 years
Transformer stations	40 years
Transformwers and meters	25 to 40 years
Plant and equipment	10 to 30 years
Other	3 to 8 years

Construction in progress comprises PP&E under construction; not yet placed into service; and pre-construction activities related to specific projects expected to be constructed. An allowance for the outlay of funds employed during the construction period has been applied to the related PP&E as allowed by the OEB.

(f) Impairment of long-lived assets

The Corporation reviews long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of the long-lived assets is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

2. Significant accounting policies (continued)

(g) Intangibles

Intangibles include computer software and land rights. Computer software is stated at cost and amortized on a straight-line basis over three years while land rights are stated at cost, are not amortized and as they have an indefinite useful life.

(h) Rate regulated assets and liabilities

Regulatory assets/liabilities represent costs/revenue that have been deferred and that are expected to be disposed of through future rates. Retail Settlement Variance Amounts ("RSVA") are required to be recorded by the OEB and arise from differences in amounts billed to customers and retailers and the cost to the Corporation, for electricity, wholesale market services and transmission services. The Corporation accrues interest on regulatory assets and liabilities as permitted by the OEB.

As at December 31, 2010, regulatory assets and liabilities are comprised principally of deferred Smart Meter costs, future income taxes and RSVA's. The Corporation has provided a provision against certain regulatory assets and liabilities, and continues to assess the likelihood of recovery of these regulatory assets and liabilities. The Corporation believes that it is probable that its regulatory assets and liability balances will be factored into the setting of future rates.

(i) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford Hydro. Goodwill is not amortized but is tested for impairment annually or more frequently if events or circumstances change that indicate that the asset may be impaired. When the carrying amount of goodwill exceeds the implied fair value an impairment loss is recognized in an amount equal to the excess.

(j) Pension and other post-employment benefits

(i) Pension

The Corporation provides a pension plan to its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer defined benefit pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The pension plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.
The Corporation accounts for its participation in OMERS, a multi-employer public sector pension fund, as a defined contribution plan. The Corporation recognizes the expense related to this plan as contributions are made.

(ii) Other post-employment benefits

The Corporation provides certain health, dental and life insurance benefits. This benefit plan provides benefits to employees when they retire from the Corporation.

The Corporation actuarially determines the cost of post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-employment benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ending at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs. This accounting policy for post-employment benefits was applied on the prospective basis. The transitional obligation resulting from this treatment is being amortized over the average remaining service period of employees.

2. Significant accounting policies (continued)

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as a current liability. Interest is paid on customers' deposits.

(l) Payment in lieu of corporate income taxes ("PILs")

The Corporation follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized based on the expected future tax consequences of differences between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

Where the Corporation expects the future income taxes to be recovered from or refunded to the customers as part of the rate setting process, the future income tax assets and liabilities result in an offsetting regulatory liability or asset account, otherwise the future income tax assets and liabilities result in a future provision that is charged to the statement of earnings and comprehensive income and retained earnings.

(m) Measurement uncertainty

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue, inventories, regulatory assets and liabilities, goodwill, employee future benefits and income taxes payable are reported based on amounts expected to be recovered/refunded and an appropriate allowance has been provided based on managements' best estimate of unrecoverable amounts. Due to the inherent uncertainty involved in making such estimates, actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB, the Minister of Energy and Infrastructure and the Minister of Finance.

3. Changes in accounting policies

Future accounting changes

International Financial Reporting Standards ("IFRS")

In September 2010, the Accounting Standards Board of Canada ("AcSB") approved an optional one year deferral for qualifying entities with rate-regulated activities. The Corporation has elected to take the one year deferral; accordingly the adoption of IFRS will occur on January 1, 2012. Thus, the Corporation will continue to prepare its financial statements in accordance with Canadian GAAP for 2011.

The adoption of IFRS will require the restatement, for comparative purposes, of the amounts reported by the Corporation for its December 31, 2011 year end, and the opening balance sheet as at January 1, 2011. The Corporation has an internal initiative to govern the conversion process to IFRS and is continuing to evaluate the impact of IFRS on its financial statements which is not yet determinable. The Corporation does, however expect an increase in the amount of disclosure requirements resulting from IFRS.

The Corporation will continue to monitor the progress made by the International Accounting Standards Board ("IASB") on the rate-regulated activities in consultation with other local distribution companies ("LDCs") and its professional advisor.

4. Inventories

During fiscal 2010, an amount of $nil (2009 - $31) was recorded as an expense for the write-down of obsolete or damaged inventory.

5. Property, plant and equipment

			2010	2009
	Cost	Accumulated depreciation	Net book value	Net book value
	$	$	$	$
Land	10,875	-	10,875	8,923
Buildings	53,225	7,689	45,536	55,132
Transformer stations	155,935	46,876	109,059	73,687
Transformers and meters	306,909	144,961	161,948	148,337
Plant and equipment	899,980	435,094	464,886	437,587
Other	43,048	30,664	12,384	12,707
Assets under capital lease	18,280	731	17,549	-
Construction in progress	26,786	-	26,786	59,227
Major spare parts	8,404	-	8,404	8,843
	1,523,442	666,015	857,427	804,443
Capital contributions	277,010	61,642	215,368	202,679
	1,246,432	604,373	642,059	601,764

Included in PP&E costs is an amount of $7,196 (2009 - $5,683) related to an "allowance for the outlay of funds" employed during the construction period as allowed by the OEB. In the absence of rate regulation, interest expense in the current year would have been higher by $1,513 (2009 - $1,433).

Major spare parts amounting to $nil (2009 - $1,061) were considered to be impaired, as they had not been utilized for several years and were no longer in compliance with current standards. The fair value was determined to be $nil, as the assets could only be sold as scrap with nominal proceeds. The 2009 impairment loss was recorded in the operating expense line of the statement of earnings and comprehensive income.

6. Intangibles

Intangible assets consist of the following:

			2010	2009
	Cost	Accumulated amortization	Net book value	Net book value
	$	$	$	
Land rights	730	-	730	729
Computer software	18,528	15,078	3,450	2,885
	19,258	15,078	4,180	3,614

7. Regulatory assets and liabilities

In its 2009 rate application, the Corporation received approval to repay net regulatory liabilities accrued from January 1, 2005 to December 31, 2007 plus interest thereon to April 30, 2009 over the period September 1, 2009 to April 30, 2011, for the former PowerStream Inc. rate zone. In its 2010 rate application, relating to the former Barrie Hydro Distribution Inc. rate zone, the Corporation has received approval to repay net regulatory liabilities accrued from January 1, 2005 to December 31, 2008 plus interest thereon to April 30, 2010 over the period May 1, 2010 to April 30, 2011.

Regulatory assets and liabilities arise as a result of the rate-making process and consist of the following:

	2010	2009
	$	$
Regulatory assets		
Deferred smart meter costs	**29,191**	25,713
Other regulatory assets	**2,770**	720
Regulatory assets	**31,961**	26,433
Regulatory liabilities		
Retail settlement variance accounts	**(1,157)**	(1,010)
Future income taxes	**(53,313)**	(61,665)
Regulatory assets recovery account	**(8,193)**	(22,915)
PILs variance	**(4,109)**	(4,008)
Provision for regulatory assets and liabilities	**(1,542)**	(1,542)
Regulatory liabilities, including the provision	**(68,314)**	(91,140)

(a) Regulatory assets

(i) Deferred smart meter costs

As part of the Ontario Government's initiative, the Corporation had installed 297,000 smart meters as at December 31, 2010 (2009 - 225,000). The Corporation has recorded the capital spending and incremental expenses incurred in connection with smart meters less amount capitalized to PP&E when smart meter rate applications are approved by the OEB along with related funding collected from the customer in the deferral accounts established by the OEB.

In 2010, the Corporation submitted an application and received approval from the OEB for the recovery of costs associated with smart meters installed in the former PowerStream Inc. rate zone in 2008 and 2009. This resulted in new rate riders effective January 1, 2011. The rate riders allow the smart meter revenue requirement to be reflected in the Corporation's rates. In addition the approval also resulted in the recognition of the following amounts that were recorded in the smart meter deferral accounts: smart meter funding amounts previously collected in the amount of $6,481 as distribution revenue, operating costs of $2,960, PP&E of $18,285 and depreciation of $1,227.

In the absence of this regulatory treatment, PP&E would have increased by $21,031 (2009 - $19,883) with related depreciation expense of $877 (2009 - $878). Operating expenses would have increased by $1,828 (2009 - $814). Other revenue would have increased by $5,898 (2009 - $4,093) and interest revenue would have been lower by $167 (2009 - $164).

This regulatory asset balance also includes the net book value less proceeds of stranded mechanical meters, which have been replaced by smart meters, in the amount of $13,497 (2009 - $10,184). In the absence of this regulatory treatment, current year replaced meters with a net book value of $4,360 (2009 - $3,747) would have been recorded as a loss on disposal of PP&E.

7. Regulatory assets and liabilities (continued)

(a) Regulatory assets (continued)

(ii) Other regulatory assets

Other regulatory accounts consist of accrued deferred costs which are listed in the table below:

	2010	2009
	$	**$**
Other regulatory assets		
Late payment class action suit settlement - (a)	**1,024**	-
Ministry of Energy and Infrastructure special purpose charge - (b)	**1,103**	-
IFRS transition costs	**232**	615
Other	**411**	105
Other regulatory assets	**2,770**	720

(a) Late Payment Penalty ("LPP") Class Action Suit Settlement

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action. As its share of this settlement, the Corporation is required to pay $1,024 on June 30, 2011 to the United Way to assist low income electricity users. In February 2011 the Corporation received approval from the OEB to recover this amount from ratepayers. The Corporation has accrued this liability and recorded a corresponding regulatory asset. Under non regulated reporting, current year expenses would have been $1,024 higher.

(b) Ministry of Energy and Infrastructure ("MEI") Special Purpose Charge

On March 16, 2010 Ontario Regulations 66/10 and 67/10 were filed for the purpose of creating a means for the Province of Ontario to recover $53,695 from electricity distributors and the IESO relating to the period from April 1, 2009 to March 31, 2010 in order to partially fund conservation programs. The Corporation is allowed to recover this apportioned amount from customers through a uniform provincial kWh charge of 0.03725 cents/kWh on electricity used for the period May 1, 2010 to April 30, 2011. Both amounts collected from the customer and the amount paid are recorded in a new variance account as directed by the OEB.

Under non-regulated reporting this charge would be classified as a receivable on the balance sheet.

(b) Regulatory liabilities

(i) Retail settlement variance accounts

RSVA are variances that have occurred since May 1, 2002 when the competitive electricity market was declared open, to December 31, 2010, and have accumulated pursuant to direction from the OEB. Current balances represent variances:

- from January 1, 2008 to December 31, 2009 for the former PowerStream Inc. rate zone;
- from January 1, 2009 to December 31, 2009 for the former Barrie Hydro Distribution Inc. rate zone; and
- from January 1, 2010 to December 31, 2010 for the Corporation's combined service area.

7. Regulatory assets and liabilities (continued)

(b) Regulatory liabilities (continued)

(i) Retail settlement variance accounts (continued)

Balances up to December 31, 2007 were approved for settlement with customers in 2009 rates for the former PowerStream Inc. rate zone and up to December 31, 2008 in 2010 rates for the former Barrie Hydro Distribution Inc. rate zone. Specifically, these amounts include:

a) Variances between the amounts charged by the IESO for:

- the operation of the markets and grid;
- the purchase of imported power by the IESO to augment Ontario's power supply and charged by the IESO as an uplift charge that is part of the wholesale market service charges; and
- various wholesale market settlement charges and transmission charges, as compared to the amount billed to consumers based on the OEB-approved wholesale market service rate and transmission rates.

b) Differences between the amounts charged by the IESO and billed to consumers for energy costs.

Energy charges by the IESO consist of the hourly price of electricity, global adjustment charges related to the Ontario Power Authority's long term contracted supply of electricity including renewables, and adjustments for electricity billed to customers at regulated price plan rates.

Under non regulated reporting, the current year cost of power would have been $6,041 lower (2009 - $4,484 higher) and interest expense would have been lower by $15 (2009 - $360).

(ii) Future income taxes

The recovery from, or refund to, customers of future income taxes by the corporation in future electricity rates is required by Section 3465 of the CICA Handbook to be recognized as an asset or liability. Accordingly the corporation has recorded a future income tax asset related to the regulated business of $53,313 and a corresponding regulatory liability of $53,313. Under non regulated reporting, income tax expense would have been $6,291 (2009- $5,135) higher.

(iii) Regulatory assets recovery account ("RARA")

The RARA is comprised of the cumulative balances of regulatory assets and regulatory liabilities approved for disposition by the OEB, reduced by amounts settled with customers through billing of approved disposition rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and rates.

As at December 31, 2010, the balances include the following:

a) Former Barrie Hydro Distribution Inc. rate zone

On May 1, 2008, the Corporation began recovery of regulatory asset balances in the amount of $910 over a period of 36 months through rate riders. These recoveries are based on final balances approved by the OEB reflecting costs to December 31, 2006 and carrying interest charges accrued to April 30, 2008. In 2008 the approved amounts were netted with the recoveries account in accordance with OEB direction.

On May 1, 2010, the Corporation began refunding net regulatory liabilities in the amount of $6,469 over a period of 12 months through rate riders. The approved amounts were netted with the recoveries account in accordance with OEB direction.

7. Regulatory assets and liabilities (continued)

(b) Regulatory liabilities (continued)

(iii) Regulatory assets recovery account ("RARA") (continued)

b) Former PowerStream Inc. rate zone

On September 1, 2009, the Corporation began refunding net regulatory liabilities in the amount of $28,089 over a period of 20 months through rate riders. These recoveries are based on final balances approved by the OEB reflecting costs to December 31, 2007 and carrying interest charges accrued to April 30, 2009. In 2009 the approved amounts were netted with the recoveries account in accordance with OEB direction.

Under non regulated reporting, current year revenues would have been decreased by $20,749 (2009 - $5,036) and interest expense in 2010 would have been decreased by $119 (2009 - $573).

(iv) PILs variance

For the period of October 1, 2001 to April 30, 2006, PILs were recorded based on the OEB PILs methodology of PILs billed amount versus PILs proxy amount variances and an annual Spreadsheet Implementation Model for PILs ("SIMPILs") filing with specified true-ups.

The OEB has undertaken a combined proceeding (EB-2008-0381) to review the balances set up in this account, for a group of utilities (the former Barrie Hydro Distribution Inc., ENWIN Utilities Ltd. and Halton Hills Hydro Inc.) and to determine the amounts to be recovered from or repaid to customers.

As an outcome of this proceeding, the OEB will provide clarification of the existing rules and interpretations as to how these rules should have been applied. It is the OEB's stated intention that these clarifications and interpretations will be used as a reference in determining the amounts for disposition by other utilities.

This proceeding is in progress and the outcome is indeterminable at this time. Any adjustments will be recorded when known.

Under non regulated reporting, current year revenues would have been $68 (2009 - $241) higher and interest expense would have been $33 (2009 - $51) lower.

(v) Provision for regulatory assets and liabilities

The Corporation has determined that there is uncertainty concerning the future recovery/settlement of certain regulatory assets and liabilities. Based on this uncertainty, a net regulatory liability provision in the amount of $1,542 (2009 - $1,542) has been recorded, of which $126 (2009 - $126) relates to regulatory assets and $1,416 (2009 - $1,416) relates to regulatory liabilities.

8. Accounts payable and accrued liabilities

	2010	2009
	$	$
Accounts payable - energy purchases	**59,689**	57,581
Payroll payable	**5,120**	5,173
Debt retirement charge payable	**4,340**	4,463
Interest payable	**3,089**	2,484
Commodity taxes payable	**1,967**	290
Current portion of construction deposits	**-**	129
Customer receivables in credit balances	**8,263**	7,732
Other accounts payable and accrued liabilities	**22,871**	32,553
	105,339	110,405

9. Related party balances and transactions

The amount due to related parties is comprised of amounts payable to the City of Vaughan, the Town of Markham and the City of Barrie and their wholly-owned subsidiaries. The below information includes transaction and balances not already disclosed in Note 11(c) and Note 14.

Components of the amounts due to related parties are as follows:

	2010	2009
	$	$
City of Vaughan	**5,420**	5,523
Town of Markham	**5,073**	4,951
City of Barrie	**1,721**	1,575
	12,214	12,049

Other significant related party transactions not otherwise disclosed separately in the financial statements, are summarized below:

			2010			2009
	City of Vaughan	**Town of Markham**	**City of Barrie**	City of Vaughan	Town of Markham	City of Barrie
	$	$	$	$	$	$
Revenue						
Energy and distribution	**4,594**	**4,367**	**5,509**	4,094	3,903	3,726
Shared services	**1,953**	**2,468**	**1,000**	1,916	1,401	1,620
Expenses						
Facilities rental	**284**	**-**	**-**	732	120	-
Realty taxes	**567**	**174**	**299**	530	158	303
Operations	**381**	**-**	**-**	482	95	-

These transactions are in the normal course of operations and are recorded at the exchange amount.

During the year the Corporation entered into operating leases with the City of Vaughan, Town of Markham and City of Barrie to lease rooftops on a number of buildings for which solar panels will be installed. There has been no financial impact of these leases for the year ended December 31, 2010.

10. Short-term debt

(a) Credit facilities

On December 17, 2008 the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $25,000 for a specific purpose, and an uncommitted Letter of Guarantee facility of $15,000.

As at December 31, 2010, the Corporation had utilized $12,484 (2009 - $12,000) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2010, an additional $444 (2009 - $46) of the uncommitted Letter of Guarantee facility was utilized as security for operation projects.

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at prime plus 0.15% or Bankers' Acceptance of a stamping fee plus 110 basis points (1.10% per annum). The uncommitted demand facility bears an interest rate of prime minus 0.10% or Bankers' Acceptance of a stamping fee plus 90 basis points (0.90% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The amount of short-term debt drawn on the credit facilities consists of:

	2010	2009
	$	$
Uncommitted demand facility	**25,000**	25,000
364-day committed revolving credit facility	**15,000**	15,000
	40,000	40,000

(b) Ontario Infrastructure Projects Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Solar business. The funding is available for up to 5 years from the date that the agreement was signed.

As at December 31, 2010, the Corporation has utilized $827 of the $90,000 financing facility. Each advance shall bear interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2010 was 1.74% and interest expense for the year was $0.670.

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the unadvanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010 and subsequently from the date of the draw of any such funds until the earlier of the facility termination date October 15, 2015 or the full advance of the committed amount. The financial covenants require a debt service coverage ratio of 1 to 1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher.

11. Long-term debt

(a) *Bank term loan*

The bank term loan of $50,000 is a 5 year fixed rate term loan with a Canadian Chartered Bank which bears interest at an annual rate of 5.08%. It is a non-amortizing loan with repayment at the end of the contracted term, February 26, 2013. The financial covenants require a total debt to capitalization ratio of no greater than 0.60:1, and to maintain an interest coverage ratio of no less than 1.25:1.

Interest expense relating to the bank term loan for the year ended December 31, 2010 was $2,540 (2009 - $2,540).

(b) *Debentures payable*

	2010	2009
	$	$
6.45% unsecured debentures due August 15, 2012, interest payable in arrears semi-annually on August 15 and February 15	**123,765**	123,091

In August 2002, the four predecessor corporations (Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc., Richmond Hill Hydro Inc. and Barrie Hydro Distribution Inc.) raised gross proceeds of $125,000 through a private placement offering. These predecessor corporations were four of five LDCs that participated in the Electricity Distributors Finance Corporation ("EDFIN") 10 Year Debenture Issue (Series 2002-1) that was offered on a private placement. EDFIN is a specific purpose corporation managed by MEARIE Management Inc., for the purpose of providing the LDCs with efficient access to the debt capital markets. Each LDC has executed a debenture which is a direct and unsecured obligation of the LDC. The LDC's obligations are several and not joint, and each LDC is liable for its own obligation and not that of any other LDC.

The debentures are recorded at amortized cost, using the effective interest method. Interest expense relating to the debentures payable was $8,737 (2009 - $8,691) which included $674 (2009 - $629) of accretion.

The debentures are subject to a financial covenant. This covenant requires that the consolidated funded obligation does not exceed 75% of the total consolidated capitalization of the Corporation.

(c) *Notes payable*

	2010	2009
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	8,743
Promissory note issued to the Town of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the Town of Markham	**7,585**	7,585
Promissory note issued to the City of Barrie	**20,000**	20,000
	182,430	182,430

11. Long-term debt (continued)

(c) Notes payable (continued)

On June 1, 2004 an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On June 1, 2004 an unsecured 20 year term promissory note was issued to the Town of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the sum of $20,000. Interest for fiscal 2010 is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the Town of Markham, and the City of Barrie, with subordination and conditions. These notes have been classified as long-term as it is not the intent of the City of Vaughan, the Town of Markham, or the City of Barrie to demand repayment within the next year.

At the request of the City of Vaughan and the Town of Markham, eight quarters of interest have been deferred commencing October 1, 2006. This deferred interest will be repayable in full on October 31, 2013 and is subject to the same interest rate and conditions as the original note.

Interest of $4,853 (2009 - $4,853) on the note payable to the City of Vaughan, $4,210 (2009 - $4,210) on the note payable to the Town of Markham and interest of $1,116 (2009 - $1,300) to the City of Barrie was charged to interest expense during the year. This includes interest on the related deferred interest balance for the City of Vaughan and the Town of Markham.

12. Employee future benefits

The Corporation measures its accrued benefit obligation for accounting purposes every three years. The latest actuarial valuation was performed as at December 31, 2009.

On June 30, 2010, the Corporation signed a new three year collective agreement with the Power Workers Union. As a result of the new agreement, limited employee post-employment benefits were extended to all union employees and any union employees hired during the term of the collective bargaining agreement. An actuarial review was undertaken only for the additional employees added to the post-employment benefit plan. This was for the period July 1, 2010 to December 31, 2010.

In December 2010 the Corporation approved extending the post-employment benefit plan to all management employees effective February 2011 on the same basis as noted above for the union employees. As a result, the accrued benefit liability was increased by $627 for the additional management employees.

A reconciliation of the Corporation's accrued benefit obligation to the amounts recorded in the financial statements is as follows:

	2010	2009
	$	$
Accrued benefit obligation	**20,297**	16,490
Unamortized transitional obligation	**(417)**	(482)
Unamortized net actuarial losses	**(5,285)**	(3,972)
Unamortized past service costs	**(588)**	-
Accrued benefit liability December 31, 2010	**14,007**	12,036

12. Employee future benefits (continued)

Details of the accrued benefit obligation are as follows:

	2010	2009
	$	$
Accrued benefit obligation, beginning of the year	16,490	13,441
Current service cost	418	260
Interest cost on obligation	951	878
Unamortized past service costs	1,261	-
Benefit payments	(428)	(393)
Actuarial losses	1,605	2,304
Accrued benefit obligation, end of the year	20,297	16,490

The plan expense for the year is determined as follows:

	2010	2009
	$	$
Current service cost	418	260
Interest cost on obligation	951	878
Amortization of transitional obligation	72	70
Amortization of past service costs	38	-
Amortization of net actuarial losses	292	108
Plan expense	1,771	1,316

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation are as follows:

	%
Discount rate	5.00 - 5.50
Rate of compensation increase	3.50
Medical benefits costs escalation - hospitalization	5.00 - 8.30
Medical benefits costs escalation - extended health care	5.00 - 8.30
Dental benefits costs escalation	5.00

Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2010:

	Increase	Decrease
	$	$
Total service and interest cost	270	(147)
Accrued benefit obligation	3,078	(2,456)
	3,348	(2,603)

13. Pension

The Corporation provides a pension plan to its full time employees through OMERS, a multi-employer plan. The Corporation incurred $3,150 (2009 - $2,536) of contribution expense during the year ended December 31, 2010.

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A common shares. The issued share capital is as follows:

		2010	2009
		$	$
100,000	Common shares	**247,183**	247,183
4,056	Class A common shares, non-voting	**2,435**	-
		249,618	247,183

Of the total 100,000 common shares issued 45,315 common shares are registered under Vaughan Holdings Inc. (wholly owned the City of Vaughan), 34,185 common shares are registered under Markham Enterprises Corporation (wholly owned by the Town of Markham) and 20,500 common shares are registered under Barrie Hydro Holdings Inc. (wholly owned by the City of Barrie).

On November 23, 2010 a Subscription Agreement was signed between the Corporation and its Shareholders for new Class A common shares for the purposes of the Shareholders providing equity for the Corporation's solar business. The articles of incorporation and shareholders agreement were amended in order to proceed with the subscription agreement. The maximum amount of Class A common shares that are available under the subscription agreement is 100,000.

Of the total 4,056 Class A common shares issued 1,838 Class A common shares are registered under Vaughan Holdings Inc. (wholly owned the City of Vaughan), 1,387 Class A common shares are registered under Markham Enterprises Corporation (wholly owned by the Town of Markham) and 831 Class A common shares are registered under Barrie Hydro Holdings Inc. (wholly owned by the City of Barrie).

Dividends

The Corporation has established a dividend policy to distribute a minimum dividend on the common shares of 50% of net income with consideration given to the:

- Cash position at the beginning of the year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

In 2010, the Corporation paid a dividend on the common shares of $10,532. During 2009, the Corporation paid $11,274 to the shareholders based on the combined net income of the predecessor corporations. In addition, the Corporation made a special payment of $19,808 to the shareholders as the final closing adjustment for the amalgamation of PowerStream Inc. and Barrie Hydro Distribution Inc.

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member's claims experience. Coverage is provided to a level of $24,000 per incident.

16. Leases

On October 9, 2008, the Corporation entered into a 25 year lease agreement relating to its operation centre. The lease term commenced January 1, 2010 and occupancy occurred in March 2010. Upon entering into this lease arrangement, the Corporation evaluated whether substantially all of the benefits and risks of ownership related to this operation centre have been transferred to the Corporation (the lessee) in order to determine if the lease is classified and recorded as capital or operating. The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a capital lease.

The Corporation is also committed to lease agreements for various vehicles and equipment that have been classified as operating leases.

The annual basic rent for capital and operating leases are as follows:

	Capital	Operating
	$	$
2011	1,430	1,128
2012	1,430	1,204
2013	1,430	1,162
2014	1,430	1,145
2015	1,430	1,143
2016 and thereafter	29,285	22,268
	36,435	28,050
Less: amounts representing interest	18,497	
	17,938	
Less: current portion of capital lease obligation	259	
Capital lease obligation	17,679	

Interest on the lease obligation during fiscal 2010 amounted to $1,087 based on the rate of 6.57% per annum. Amortization of the corresponding capital asset during fiscal 2010 amounted to $731 based on the straight-line method with a useful life equal to the term of the lease (25 years).

17. Contingencies

(a) Legal claims

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Ministry of Finance tax audits

The Ministry of Finance (the "Ministry") has conducted PILs audits of the taxation years up to and including the 2006 year.

There remains an outstanding matter regarding the treatment of the RSVA for tax purposes.

There has been inconsistent practice of tax treatment of certain regulatory asset/liability accounts among LDCs across Ontario.

In accordance with OEB regulations, the Corporation has recorded the variance between amounts charged by the Corporation to its customers (at the OEB prescribed rates) and the costs charged to the Corporation for electricity, market services and transmission services, namely retail settlement variances, as regulatory assets or liabilities on the financial statements. Similar treatment has been followed for tax purposes. The Ministry is questioning this treatment of the RSVA for tax purposes and is suggesting that RSVA liabilities may be considered income for tax purposes.

The Ministry is currently reviewing the treatment of RSVA for tax purposes on a province wide basis. The impact of a tax ruling may result in a reassessment of taxes payable which could have an impact on results, financial position and cash flows in the future. The outcome of the Ministry's review is not determinable and as such, amounts will be recorded as necessary.

18. Financial instruments and risk management

(a) Recognition and measurement

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 2(c).

The Corporation's carrying value and fair value of financial instruments are as follows:

		2010		2009
Description	**Carrying value**	**Fair value**	Carrying value	Fair value
	$	**$**	$	$
Assets				
Cash	**8,568**	**8,568**	42,612	42,612
Accounts receivable (net of allowance for doubtful accounts)	**69,366**	**69,366**	73,633	73,633
	77,934	**77,934**	116,245	116,245
Liabilities				
Accounts payable and accrued liabilities	**105,339**	**105,339**	110,405	110,405
Customer deposits	**13,549**	**13,549**	17,726	17,726
Due to related parties	**12,214**	**12,214**	12,049	12,049
Short-term debt	**40,000**	**40,000**	40,000	40,000
Infrastructure Ontario financing	**827**	**827**	-	-
Bank term loan	**50,000**	**52,529**	50,000	53,686
Debentures payable	**123,765**	**131,326**	123,091	135,391
Notes payable	**182,430**	**207,468**	182,430	198,901
	528,124	**563,252**	535,701	568,158

The fair value of financial instruments has been calculated using the market interest rates as at December 31, adjusted for the Corporation's risk rating. The Corporation uses Level 1 classifications for fair value measurements for most of its financial instruments and Level 2 classifications for the bank term loan, debentures payable and notes payable.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

18. Financial instruments and risk management (continued)

(c) *Credit risk*

The Corporation's primary source of credit risks to its accounts receivable result from customer's failing to discharge their dues for electricity consumed and billed. The Corporation has approximately 325,000 (2009 - 321,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $17,043 (2009 - $21,872) in accordance with OEB guidelines, reviewing Dun & Bradstreet (D&B) reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for $4,500 (2009 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2010		2009	
	Total		Total	
	$	**$**	$	$
Less than 30 days	**55,435**	**78**	55,965	73
30 - 60 days	**8,493**	**12**	4,346	6
61 - 90 days	**3,434**	**5**	4,336	6
Greater than 91 days	**4,082**	**5**	11,161	15
Total outstanding	**71,444**	**100**	75,808	100
Less: Allowance for doubtful accounts	**(2,078)**	**(3)**	(2,175)	(3)
	69,366		73,633	

As at December 31, 2010, there was no significant concentration of credit risk with respect to any class of financial assets.

(d) *Interest rate risk*

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short term borrowing may expose the Corporation to short term interest rate fluctuations as follows:

	2010	2009
364 day revolving facility		
Prime based loans	**PR*+0.15% p.a.**	PR*+0.25% p.a.
Bankers Acceptances	**SF*+1.10% p.a.**	SF*+1.37% p.a.
Demand facility		
Prime based loans	**PR*-0.10% p.a.**	PR*+0.00% p.a.
Bankers acceptances	**SF*+0.90% p.a.**	SF*+1.00% p.a.
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.
Committed term facility (Fixed Rate for 5 Years)	**5.08% p.a.**	5.08% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	-

Note: PR- Prime Rate, SF* - Stamping Fee*

18. Financial instruments and risk management (continued)

(d) Interest rate risk (continued)

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points) would increase or decrease the annual interest expense by approximately $400.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. These interest rate fluctuations could impact the level of interest income earned by the Corporation.

(e) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts. The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with financial liabilities are as follows:

	2010			2009	
Maturity period	**Principal ***	**Interest**	**Total**	Principal *	Interest
	$	**$**	**$**	$	$
Less than 1 year	**117,553**	**-**	**117,553**	123,454	-
1-5 years	**231,327**	**22,159**	**253,486**	231,327	33,673
6-10 years	**-**	**-**	**-**	-	-
Over 10 years	**166,102**	**124,353**	**290,455**	166,102	133,621
	514,982	**146,512**	**661,494**	520,883	167,294

* The principal includes $1,908 of deferred issuing cost amortization

(f) Hedging / Derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes. The Corporation has not entered into any such transactions during the year.

19. Capital disclosures

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the distribution business.

(ii) Ensure compliance with various covenants related to its long-term/short-term debt, promissory notes and debentures.

(iii) Consistently maintain a high credit rating for the Corporation.

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB.

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning.

(vi) Deliver appropriate financial returns to shareholders.

19. Capital disclosures (continued)

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2010 is as follows:

	2010	2009
	$	$
Shareholders' equity		
Share capital (Note 14)	**249,618**	247,183
Retained earnings	**36,999**	21,064
Total equity	**286,617**	268,247
Short-term debt		
Short-term debt (Note 10 (a))	**40,000**	40,000
Infrastructure Ontario financing (Note 10 (b))	**827**	-
Long-term debt		
Bank term loan (Note 11 (a))	**50,000**	50,000
Debenture payable (Note 11 (b))	**123,765**	123,091
Notes payable (Note 11 (c))	**182,430**	182,430
Total debt	**397,022**	395,521
Total capital	**683,639**	663,768

As at December 31, 2010, the Corporation was in compliance with all covenants included in its short-term debt, bank term loan, debentures payable and notes payable. Details relating to debt covenants are disclosed in Note 10 and Note 11.

The Corporation is within the debt and equity requirements of the OEB.

The Corporation's dividend policy is disclosed in Note 14.

20. Corporate income taxes

The provision for PILs is comprised of the following:

	2010	2009
	$	$
Current income taxes	**10,527**	8,561
Future income liabilities	**61**	-
	10,588	8,561

(a) Current taxes

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is provided as follows:

	2010	2009
	$	$
Income from operations before PILs	**37,055**	29,625
Statutory Canadian federal and provincial income tax rates	**31.00%**	33.00%
Expected tax provision on income at statutory rates	**11,487**	9,776
Increase (decrease) in income taxes resulting from timing differences:		
Amortization/CCA differences	**(2,776)**	(2,755)
Post employment benefits	**611**	305
Eligible capital expenditures	**(166)**	(227)
Other reserves	**368**	590
Revenue and overheads related to smart meters recognized for tax purposes but capitalized for accounting purposes	**604**	401
Other	**569**	577
Permanent differences	**(109)**	(106)
Provision for PILs	**10,588**	8,561

20. Corporate income taxes (continued)

(b) *Future income tax assets*

Future income tax assets of $53,313 (2009 - $61,665), and a corresponding regulatory liability of $53,313 (2009 - $61,665) were recorded as at December 31, 2010. Significant components of the Corporation's future income tax assets and liabilities are as follows:

	2010	2009
	$	$
Employee future benefits	**4,377**	3,943
Property, plant, equipment and intangible assets	**46,126**	56,235
Smart meter revenues/costs	**1,914**	1,543
Other taxable temporary differences	**896**	(56)
	53,313	61,665

(c) *Future income tax liabilities*

Future income tax liabilities of $61 were recorded as at December 31, 2010. The future tax liabilities relate to taxable temporary differences. This amount is not offset by a regulatory asset, as it relates specifically to the Corporation's non-regulated solar business.

21. Net change in non-cash operating working capital

	2010	2009
	$	$
Accounts receivable	**4,267**	(9,586)
Unbilled revenue	**(4,047)**	(11,501)
Income taxes recoverable	**1,525**	2,206
Inventories	**819**	126
Prepaid and other	**(137)**	96
Accounts payable and accrued liabilities	**(7,372)**	(11,853)
Current portion of customer deposits	**478**	-
Increase in due to related parties	**165**	2,150
Income taxes payable	**1,588**	5,034
	(2,714)	(23,328)

22. Net interest expense

	2010	2009
	$	$
Interest expense	**22,421**	21,886
Interest income	**(407)**	(272)
	22,014	21,614

23. Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(a) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

(b) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(c) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

24. Comparatives

In certain instances, the prior year information presented for comparative purposes has been reclassified to conform to the financial statement presentation adopted for the current year.

Schedule 16

FINANCIAL STATEMENTS – 2011 AUDITED

Financial statements of

PowerStream Inc.

December 31, 2011

PowerStream Inc.
December 31, 2011

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Deloitte.

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Independent Auditor's Report

To the Shareholders of
PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2011, and the statements of earnings and comprehensive income and retained earnings and of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement to the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2011, and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
April 25, 2012

PowerStream Inc.

Balance sheet
as at December 31, 2011

(In thousands of dollars)

	2011	2010 (Restated - Note 20(b))
	$	$
Assets		
Current assets		
Cash	**-**	8,568
Accounts receivable, net of allowance for doubtful accounts (Note 18(c))	**86,933**	69,366
Unbilled revenue	**90,369**	92,207
Inventories (Note 4)	**3,267**	3,050
Prepaids and other	**3,035**	2,718
	183,604	175,909
Property, plant and equipment, net (Note 5)	**690,041**	642,059
Regulatory assets (Note 7(a))	**14,591**	31,961
Intangibles, net (Note 6)	**6,852**	4,792
Future income tax assets (Note 20(b))	**49,533**	54,539
Goodwill	**42,543**	42,543
	987,164	951,803
Liabilities		
Current liabilities		
Bank indebtedness	**8,039**	-
Accounts payable and accrued liabilities (Note 8)	**116,109**	105,339
Current portion of customers' deposits	**1,005**	1,478
Income taxes payable	**3,445**	6,622
Due to related parties (Note 9)	**11,103**	12,214
Short-term debt (Note 10(a))	**40,000**	40,000
Current portion of liability for subdivision development	**2,984**	4,138
Current portion of capital lease obligation (Note 16)	**277**	259
Infrastructure Ontario financing (Note 10(b))	**3,206**	827
	186,168	170,877
Long-term liabilities		
Bank term loan (Note 11(a))	**50,000**	50,000
Debentures payable (Note 11(b))	**124,489**	123,765
Notes payable (Note 11(c))	**182,430**	182,430
Infrastructure Ontario debentures (Note 11(d))	**980**	-
Regulatory liabilities (Note 7(b))	**59,246**	69,540
Customers' deposits	**12,030**	12,071
Employee future benefits (Note 12)	**15,265**	14,007
Liability for subdivision development	**201**	1,232
Construction deposits	**33,045**	23,364
Capital lease obligation (Note 16)	**17,402**	17,679
Future Income tax liabilities (Note 20(c))	**505**	61
Other liabilities	**-**	160
	495,593	494,309
Shareholders' equity		
Share capital (Note 14)	**251,957**	249,618
Retained earnings	**53,446**	36,999
	305,403	286,617
	987,164	951,803

Approved on behalf of the Board

Director

Director

PowerStream Inc.

Statement of earnings and comprehensive income and retained earnings year ended December 31, 2011

(In thousands of dollars)

	2011	2010
	$	$
Revenues		
Sale of energy	**751,457**	691,318
Distribution revenue	**160,914**	155,841
Other revenue	**10,052**	9,229
Total revenue	**922,423**	856,388
Cost of power purchased	**751,457**	691,318
	170,966	165,070
Operating expenses	**65,492**	59,746
Earnings before amortization, interest and income taxes	**105,474**	105,324
Depreciation of property, plant and equipment and intangibles (net of $2,909 (2010 - $2,803) charged to other accounts)	**46,127**	46,255
Net interest expense (Note 22)	**23,821**	22,014
Income before income taxes	**35,526**	37,055
Income tax expense (Note 20(a))	**5,222**	10,588
Net earnings and comprehensive income for the year	**30,304**	26,467
Retained earnings, beginning of year	**36,999**	21,064
Dividends (Note 14)	**(13,857)**	(10,532)
Retained earnings, end of year	**53,446**	36,999

PowerStream Inc.

Statement of cash flows
year ended December 31, 2011

(In thousands of dollars)

	2011	2010 (Restated - Note 20(b))
	$	$
Operating activities		
Net earnings for the year	**30,304**	26,467
Adjustments to determine cash provided by operating activities		
Depreciation of property, plant and equipment	**45,950**	46,675
Accretion of debentures payable	**724**	674
Amortization of intangibles	**3,086**	2,415
Employee future benefits	**1,258**	1,971
Future income taxes	**5,450**	7,187
Change in regulatory assets/liabilities	**7,076**	(27,128)
(Gain) loss on disposal of property, plant and equipment	**(256)**	533
Net change in non-cash operating working capital (Note 21)	**(16,588)**	(2,714)
	77,004	56,080
Financing activities		
Decrease in liability for subdivisions development	**(2,185)**	(2,922)
Decrease in long-term customers' deposits	**(41)**	(4,655)
Decrease in other liabilities	**(160)**	(5,261)
Dividends paid (Note 14)	**(13,857)**	(10,532)
Increase in construction deposits	**9,681**	192
Decrease in principal on capital lease obligation	**(259)**	(342)
Increase in Infrastructure Ontario financing	**2,379**	827
Increase in Infrastructure Ontario debentures	**980**	-
	(3,462)	(22,693)
Investing activities		
Proceeds on disposal of property, plant and equipment	**275**	140
Purchase of intangibles	**(5,146)**	(2,949)
Purchase of property, plant and equipment, net of contribution of capital construction	**(87,617)**	(67,057)
Proceeds from the issuance of Class A common shares	**2,339**	2,435
	(90,149)	(67,431)
Decrease in cash during the year	**(16,607)**	(34,044)
Cash, beginning of year	**8,568**	42,612
(Bank indebtedness) cash, end of year	**(8,039)**	8,568
Supplementary cash flow information		
Cash paid during the year for:		
Interest	**23,344**	22,619
Payments in lieu of corporate income taxes	**7,649**	9,247
Acquisition of property, plant and equipment financed by capital lease	**-**	18,280

1. Description of the business

PowerStream Inc. (the "Corporation") was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is owned by the Corporation of the City of Vaughan (the "City of Vaughan"), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the Town of Markham (the "Town of Markham"), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the "City of Barrie"), through its wholly owned subsidiary, Barrie Hydro Holdings Inc.

The principal activity of the Corporation is to distribute electricity in the service area of Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under licenses issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval.

As a condition of its distribution license, the Corporation is required to meet specified Conservation and Demand Management ("CDM") targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, PowerStream is delivering Ontario Power Authority ("OPA") funded programs in order to meet its targets.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation has commenced operations of a solar generation business, in 2010, as permitted by these changes.

2. Significant accounting policies

The Corporation's financial statements are the representations of management prepared in accordance with Canadian Generally Accepted Accounting Principles ("CGAAP") and accounting policies provided by its regulator, the OEB, as contained in the Accounting Procedures Handbook for Electric Distribution Utilities, issued under the authority of the Ontario Energy Board Act, 1998.

The financial statements reflect the following significant accounting policies:

(a) Rate setting

The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

As the Corporation is regulated by the OEB, the timing of recognition and measurement of assets and liabilities arising from rate regulation in these financial statements may differ from what is otherwise expected under CGAAP for non-rate regulated enterprises. The Corporation has determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under CGAAP and this recognition is consistent with the U.S. Statement of Financial Accounting Standards No. 71 - "Accounting for the Effects of Certain Types of Regulation".

2. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the Independent Electricity System Operator ("IESO").

(ii) Other revenue

Other revenue related to the sale of other services is recognized as services are rendered. Contract revenue is accounted for using the percentage of completion method, whereby revenue is recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident.

Performance incentive payments under the CDM program are made on the basis of the Corporation's verified results in meeting its CDM targets. The Corporation will recognize the performance incentives when the amounts are measurable and collection is reasonably assured.

(c) Financial instruments

The Corporation has made the following balance sheet classifications in connection with its financial assets and financial liabilities:

(i) Cash and bank indebtedness are classified as "Held-for-Trading" and are measured at fair value.

(ii) Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost using the effective interest method.

(iii) Accounts payable and accrued liabilities, customers' deposits, amounts due to related parties, short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable, notes payable and Infrastructure Ontario debentures are classified as "Other Financial Liabilities" and are measured at amortized cost using the effective interest method.

Financial assets and liabilities are initially recorded at fair value. The fair value is the amount of the consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act. Transaction costs are netted against the proceeds of financial instruments classified as "Other Financial Liabilities" and are considered when determining the effective interest rate for the discounted cash flows. Subsequent measurement depends on how each financial instrument is classified on the balance sheet.

2. Significant accounting policies (continued)

(c) Financial instruments (continued)

The Corporation has classified fair value measurements using a fair value hierarchy that reflects three levels of inputs used in making the fair value measurements. The fair value hierarchy has the following levels:

(i) Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities;

(ii) Level 2: Observable inputs other than quoted prices included in Level 1, such as derived prices for similar assets and liabilities; or quoted prices in inactive markets; and

(iii) Level 3: Unobservable inputs for the assets or liabilities that are not based on observable market data.

(d) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, is stated at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis. Any impairment losses taken on inventories are reversed if and when net realizable value subsequently recovers. Major spare parts and standby equipment are recorded as part of property, plant and equipment and depreciated once they are put into use.

(e) Property, plant and equipment and depreciation

Property, plant and equipment ("PP&E") is recorded at cost and includes contracted services, materials, labour, engineering costs, interest and overheads. Certain PP&E assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. Such contributions, whether in cash or in-kind, are offset against the related PP&E asset cost. Contributions in-kind are valued at their fair value at the date of their contribution.

When identifiable assets, such as buildings, distribution station equipment, equipment and furniture are retired or otherwise disposed of, their original cost and related accumulated depreciation are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period.

Depreciation of PP&E is provided for on a straight-line basis over the estimated service life of the assets. Depreciation of contributions from developers or customers is depreciated at the rates corresponding with the useful lives of the related PP&E. The estimated service lives of the various assets used in calculating depreciation are summarized below:

Buildings	10 to 50 years
Transformer stations	40 years
Transformers and meters	25 to 40 years
Plant and equipment	10 to 30 years
Other	3 to 8 years

Construction in progress comprises PP&E under construction; not yet placed into service; and pre-construction activities related to specific projects expected to be constructed. An allowance for the outlay of funds employed during the construction period has been applied to the related PP&E as allowed by the OEB.

(f) Impairment of long-lived assets

The Corporation reviews long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of the long-lived assets is not recoverable. Any resulting impairment loss is recorded in the period in which the impairment occurs.

2. Significant accounting policies (continued)

(g) Intangibles

Intangibles include land rights, computer software and deferred charges. Land rights are stated at cost, and are not amortized as they have an indefinite useful life. Computer software and deferred charges are stated at cost and amortized on a straight-line basis over the estimated useful lives:

Computer software	3 years
Deferred charges	25 years

(h) Rate regulated assets and liabilities

Regulatory assets/liabilities represent costs/revenue that have been deferred and that are expected to be disposed of through future rates. Retail Settlement Variance Amounts ("RSVA") are required to be recorded by the OEB and arise from differences in amounts billed to customers and retailers and the cost to the Corporation, for electricity, wholesale market services and transmission services. The Corporation accrues interest on regulatory assets and liabilities as permitted by the OEB.

The Corporation has provided a provision against certain regulatory assets and liabilities, and continues to assess the likelihood of recovery of these regulatory assets and liabilities. The Corporation believes that it is probable that its regulatory assets and liability balances will be factored into the setting of future rates.

(i) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford Hydro. Goodwill is not amortized, but is tested for impairment annually or more frequently if events or circumstances change that indicate that the asset may be impaired. When the carrying amount of goodwill exceeds the implied fair value an impairment loss is recognized in an amount equal to the excess.

(j) Pension and other post-employment benefits

(i) Pension

The Corporation provides a pension plan to its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer defined benefit pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The pension plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.
The Corporation accounts for its participation in OMERS, a multi-employer public sector pension fund, as a defined contribution plan. The Corporation recognizes the expense related to this plan as contributions are made.

(ii) Other post-employment benefits

The Corporation provides certain health, dental and life insurance benefits. This benefit plan provides benefits to employees when they retire from the Corporation.

The Corporation actuarially determines the cost of post-employment benefits offered to employees using the projected benefit method prorated on service and based on management's best estimate assumptions. Under this method, the projected post-employment benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at the date of hire, and ending at the earliest age the employee could retire and qualify for benefits. Compensated absences and termination benefits that do not vest or accumulate are recognized as an expense when the event occurs. This accounting policy for post-employment benefits was applied on the prospective basis. The transitional obligation resulting from this treatment is being amortized over the average remaining service period of employees.

2. Significant accounting policies (continued)

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as a current liability. Interest is paid on customers' deposits.

(l) Payment in lieu of corporate income taxes ("PILs")

The Corporation follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized based on the expected future tax consequences of differences between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

Where the Corporation expects the future income taxes to be recovered from or refunded to the customers as part of the rate setting process, the future income tax assets and liabilities result in an offsetting regulatory liability or asset account, otherwise the future income tax assets and liabilities result in a future provision that is charged to the statement of earnings and comprehensive income and retained earnings.

(m) Measurement uncertainty

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue, inventories, regulatory assets and liabilities, goodwill, employee future benefits and income taxes payable are reported based on amounts expected to be recovered/refunded and an appropriate allowance has been provided based on managements' best estimate of unrecoverable amounts. Due to the inherent uncertainty involved in making such estimates, actual results could differ from amounts recorded in these financial statements, including changes as a result of future decisions made by the OEB, the Minister of Energy and Infrastructure and the Minister of Finance.

3. Changes in accounting policies

Future accounting changes

International Financial Reporting Standards ("IFRS")

In September 2010, the Accounting Standards Board of Canada ("AcSB") approved an optional one year deferral for qualifying entities with rate-regulated activities. The Corporation has elected to take the one year deferral and accordingly the adoption of IFRS is expected to occur on January 1, 2012. Additionally, in March 2012 the AcSB announced an additional optional one year deferral to January 1, 2013 related to the adoption of IFRS for qualifying entities with rate-regulated activities.

The adoption of IFRS will require the restatement, for comparative purposes, of the amounts reported by the Corporation for its December 31, 2011 year end, and the opening balance sheet as at January 1, 2011. The Corporation has an internal initiative to govern the conversion process to IFRS and is continuing to evaluate the impact of IFRS on its financial statements which is not yet determinable. The Corporation does, however expect an increase in the amount of disclosure requirements resulting from IFRS.

The Corporation will continue to monitor the progress made by the International Accounting Standards Board ("IASB") on the rate-regulated activities in consultation with other local distribution companies ("LDCs") and its professional advisors.

4. Inventories

During fiscal 2011, an amount of $109 (2010 - Nil) was recorded as an expense for the write-down of obsolete or damaged inventory.

5. Property, plant and equipment

			2011	2010
	Cost	**Accumulated depreciation**	**Net book value**	Net book value
	$	**$**	**$**	$
Land	**11,367**	-	**11,367**	10,875
Buildings	**53,530**	**8,754**	**44,776**	45,536
Transformer stations	**163,501**	**51,045**	**112,456**	109,059
Transformers and meters	**344,334**	**156,893**	**187,441**	161,948
Plant and equipment	**960,798**	**467,771**	**493,027**	464,886
Other	**43,655**	**32,985**	**10,670**	12,384
Assets under capital lease	**18,280**	**1,462**	**16,818**	17,549
Construction in progress	**31,958**	-	**31,958**	26,786
Major spare parts	**9,184**	-	**9,184**	8,404
	1,636,607	**718,910**	**917,697**	857,427
Capital contributions	**300,872**	**73,216**	**227,656**	215,368
	1,335,735	**645,694**	**690,041**	642,059

Included in PP&E costs is an amount of $7,733 (2010 - $7,196) related to an "allowance for the outlay of funds" employed during the construction period as allowed by the OEB. In the absence of rate regulation, interest expense in the current year would have been higher by $537 (2010 - $1,513).

6. Intangibles

Intangible assets consist of the following:

			2011	2010
	Cost	**Accumulated amortization**	**Net book value**	Net book value
	$	**$**	**$**	$
Land rights	**760**	-	**760**	730
Computer software	**24,646**	**19,134**	**5,512**	3,450
Deferred charges	**612**	**32**	**580**	612
	26,018	**19,166**	**6,852**	4,792

7. Regulatory assets and liabilities

In its 2009 rate application, the Corporation received approval to repay net regulatory liabilities accrued from January 1, 2005 to December 31, 2007 plus interest thereon to April 30, 2009 over the period September 1, 2009 to April 30, 2011, for the former PowerStream Inc. rate zone. In its 2010 rate application, relating to the former Barrie Hydro Distribution Inc. rate zone, the Corporation has received approval to repay net regulatory liabilities accrued from January 1, 2005 to December 31, 2008 plus interest thereon to April 30, 2010 over the period May 1, 2010 to April 30, 2011. The regulatory balances at December 31, 2011 will be considered for disposition as part of the Corporation's 2013 cost of service application.

Regulatory assets and liabilities arise as a result of the rate-making process and consist of the following:

	2011	2010 (Restated - Note 20(b))
	$	$
Regulatory assets		
Deferred smart meter costs	13,029	29,191
Other regulatory assets	1,270	2,770
Regulatory assets recovery account	292	-
Regulatory assets	14,591	31,961
Regulatory liabilities		
Retail settlement variance accounts	(3,400)	(1,157)
Future income taxes	(49,533)	(54,539)
Regulatory assets recovery account	-	(8,193)
PILs variance	(5,521)	(4,109)
Provision for regulatory assets and liabilities	(792)	(1,542)
Regulatory liabilities, including the provision	(59,246)	(69,540)

(a) Regulatory assets

(i) Deferred smart meter costs

As part of the Ontario Government's initiative, the Corporation has installed 317,000 smart meters as at December 31, 2011 (2010 - 297,000). The Corporation has recorded the capital spending and incremental expenses incurred in connection with smart meters less amount capitalized to PP&E when smart meter rate applications are approved by the OEB along with related funding collected from the customer in the deferral accounts established by the OEB.

In 2011, the Corporation submitted a final application and received approval from the OEB for the recovery of costs associated with smart meters installed in both of the Corporation's rate zones up to April 30, 2011. This resulted in new rate riders effective December 1, 2011. The rate riders allow the smart meter revenue requirement to be reflected in the Corporation's rates. In addition the approval also resulted in the recognition of the following amounts that were recorded in the smart meter deferral accounts: smart meter funding amounts previously collected in the amount of $5,285 as distribution revenue, operating costs of $1,407, PP&E of $22,282 and depreciation of $2,375.

In the absence of this regulatory treatment, operating expenses would have increased by $243 (2010 - $1,828) and interest revenue would have been lower by $34 (2010 - $167).

This regulatory asset balance includes the net book value less proceeds of stranded mechanical meters, which have been replaced by smart meters, in the amount of $12,789 (2010 - $13,497). In the absence of this regulatory treatment, current year replaced meters with a net book value of $517 (2010 - $4,360) would have been recorded as a loss on disposal of PP&E.

7. Regulatory assets and liabilities (continued)

(a) Regulatory assets (continued)

(ii) Other regulatory assets

Other regulatory assets consist of deferred costs which are listed in the table below:

	2011	2010
	$	$
Other regulatory assets		
Late payment class action suit settlement - (a)	**-**	1,024
Ministry of Energy and Infrastructure special purpose charge - (b)	**(14)**	1,103
Green Energy Renewable Connection and Smart Grid - (c)	**1,619**	483
IFRS transition costs	**(62)**	232
Other	**(273)**	(72)
Other regulatory assets	**1,270**	2,770

(a) Late Payment Penalty ("LPP") Class Action Suit Settlement

On July 22, 2010, the Ontario Superior Court of Justice approved a settlement of the LPP Class Action. As its share of this settlement, the Corporation was required to pay $1,019 on June 30, 2011 to the United Way to assist low income electricity users. In February 2011 the Corporation received approval from the OEB to recover this amount from ratepayers and transferred the amount to the recoveries account. As of May 1, 2011, the Corporation began recovering this amount from customers over a one year period. Under non-regulated reporting the amount collected in 2011 of $691 would be recorded as revenue.

(b) Ministry of Energy and Infrastructure ("MEI") Special Purpose Charge

On March 16, 2010 Ontario Regulations 66/10 and 67/10 were filed for the purpose of creating a means for the Province of Ontario to recover $53,695 from electricity distributors and the IESO relating to the period from April 1, 2009 to March 31, 2010 in order to partially fund conservation programs. The Corporation is allowed to recover this apportioned amount from customers through a uniform provincial kWh charge of 0.03725 cents/kWh on electricity used for the period May 1, 2010 to April 30, 2011. Both amounts collected from the customer and the amount paid are recorded in a new variance account as directed by the OEB.

(c) Green Energy Renewable Connection and Smart Grid

Under the Green Energy and Green Economy Act, electricity distributors are required to facilitate the connection of renewable energy sources to their systems and to undertake activities that will lead to a smart grid. The OEB has authorized deferral accounts to record the associated costs. Under non-regulated reporting, current year expenses would be higher by $392 (2010 - $206) and PP&E would be higher by $744 (2010 - $277).

(iii) Regulatory assets recovery account ("RARA")

The RARA is comprised of the cumulative balances of regulatory assets and regulatory liabilities approved for disposition by the OEB, reduced by amounts settled with customers through billing of approved disposition rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and rates.

7. Regulatory assets and liabilities (continued)

(a) Regulatory assets (continued)

(iii) Regulatory assets recovery account ("RARA") (continued)

As at December 31, 2011, the balance consists mainly of the unrecovered balance of the LPP Settlement. On May 1, 2011, the Corporation began recovery of the LPP settlement in the amount of $1,019 over a period of 12 months through rate riders. In 2011 the approved amount was netted with the recoveries account in accordance with OEB direction. As of December 31, 2011, a portion of the LPP settlement remains to be recovered from the approved rate riders which continue to April 30, 2012.

Under non-regulated reporting, current year revenues would have been decreased by $8,479 (2010 - $20,749) and interest expense in 2010 would have been increased by $6 (2010 - $119 decrease).

(b) Regulatory liabilities

(i) <u>Retail settlement variance accounts ("RSVA")</u>

RSVA are variances that have occurred since May 1, 2002 when the competitive electricity market was declared open, to December 31, 2011, and have accumulated pursuant to direction from the OEB. Current balances represent variances:

- from January 1, 2008 to December 31, 2009 for the former PowerStream Inc. rate zone;
- from January 1, 2009 to December 31, 2009 for the former Barrie Hydro Distribution Inc. rate zone; and
- from January 1, 2010 to December 31, 2011 for the Corporation's combined service area.

Balances up to December 31, 2007 were approved for settlement with customers in 2009 rates for the former PowerStream Inc. rate zone and up to December 31, 2008 in 2010 rates for the former Barrie Hydro Distribution Inc. rate zone. Specifically, these amounts include:

a) Variances between the amounts charged by the IESO for:
    - the operation of the markets and grid;
    - the purchase of imported power by the IESO to augment Ontario's power supply and charged by the IESO as an uplift charge that is part of the wholesale market service charges; and
    - various wholesale market settlement charges and transmission charges, as compared to the amount billed to consumers based on the OEB-approved wholesale market service rate and transmission rates.

b) Differences between the amounts charged by the IESO and billed to consumers for energy costs.

Energy charges by the IESO consist of the hourly price of electricity, global adjustment charges related to the Ontario Power Authority's long term contracted supply of electricity including renewables, and adjustments for electricity billed to customers at regulated price plan rates.

Under non regulated reporting, the current year cost of power would have been $2,248 lower (2010 - $6,041 lower) and interest expense would have been higher by $5 (2010 - $15 lower).

7. Regulatory assets and liabilities (continued)

(b) Regulatory liabilities (continued)

(ii) Future income taxes

The recovery from, or refund to, customers of future income taxes by the Corporation in future electricity rates is required by Section 3465 of the CICA Handbook to be recognized as an asset or liability. Accordingly the Corporation has recorded a future income tax asset related to the regulated business of $49,533 (2010 - $54,539) and a corresponding regulatory liability of $49,533 (2010 - $54,539). Under non regulated reporting, income tax expense would have been $4,005 (2010 - $5,700) higher.

(iii) PILs variance

For the period of October 1, 2001 to April 30, 2006, PILs were recorded based on the OEB PILs methodology of PILs billed amount versus PILs proxy amount variances and an annual Spreadsheet Implementation Model for PILs ("SIMPILs") filing with specified true-ups.

In 2011, the OEB concluded a combined proceeding (EB-2008-0381) to review the balances set up in this account, for a group of utilities (the former Barrie Hydro Distribution Inc., ENWIN Utilities Ltd. and Halton Hills Hydro Inc.) and approved the amounts to be recovered from or repaid to customers commencing May 1, 2012.

The OEB decision provided clarification of the existing rules and interpretations as to how these rules should have been applied. The Corporation has updated the amount to reflect the OEB Decision on the former Barrie Hydro Distribution Inc. balance and an update of the balance for the former PowerStream Inc. rate zone based on the decision.

Under non regulated reporting, current year revenues would have been $1,158 (2010 - $68) higher and interest expense would have been $254 (2010 - $33) lower.

(iv) Provision for regulatory assets and liabilities

The Corporation has determined that there is uncertainty concerning the future recovery/settlement of certain regulatory assets and liabilities. Based on this uncertainty, a net regulatory liability provision in the amount of $792 (2010 - $1,542) has been recorded, of which $126 (2010 - $126) relates to regulatory assets and $666 (2010 - $1,416) relates to regulatory liabilities.

8. Accounts payable and accrued liabilities

	2011	2010
	$	$
Accounts payable - energy purchases	**60,133**	59,689
Payroll payable	**5,125**	5,120
Debt retirement charge payable	**4,131**	4,340
Interest payable	**3,089**	3,089
Commodity taxes payable	**2,757**	1,967
Customer receivables in credit balances	**4,415**	8,263
Other accounts payable and accrued liabilities	**36,459**	22,871
	116,109	105,339

9. Related party balances and transactions

The amount due to / (from) related parties is comprised of amounts payable to / (receivable from) the City of Vaughan, the Town of Markham and the City of Barrie and their wholly-owned subsidiaries. The information below includes transaction and balances not already disclosed in Note 11(c) and Note 14.

Components of the amounts due to / (from) related parties are as follows:

	2011	2010
	$	$
City of Vaughan	**5,712**	5,420
Town of Markham	**5,846**	5,073
City of Barrie	**(455)**	1,721
	11,103	12,214

Other significant related party transactions not otherwise disclosed separately in the financial statements, are summarized below:

			2011			2010
	City of Vaughan	**Town of Markham**	**City of Barrie**	City of Vaughan	Town of Markham	City of Barrie
	$	**$**	**$**	$	$	$
Revenue						
Energy and distribution	**5,079**	**5,905**	**6,316**	4,594	4,367	5,509
Shared services	**1,725**	**2,323**	**652**	1,953	2,468	1,000
Expenses						
Facilities rental	**170**	**37**	**41**	284	-	-
Realty taxes	**748**	**410**	**290**	567	174	299
Operations	**41**	**-**	**-**	381	-	-

These transactions are in the normal course of operations and are recorded at the exchange amount.

The Corporation has certain operating leases with the City of Vaughan, Town of Markham and City of Barrie to lease rooftops on a number of buildings for which feed-in tariff contracts have been obtained. The current year lease expense has been included in the 'Facilities rental' line on the table above, and the future operating lease commitments have been included in Note 16.

10. Short-term debt

(a) *Credit facilities*

On December 17, 2008 the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $25,000 for a specific purpose, and an uncommitted Letter of Guarantee facility of $15,000.

As at December 31, 2011, the Corporation had utilized $12,484 (2010 - $12,484) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2011, an additional $555 (2010 - $444) of the uncommitted Letter of Guarantee facility was utilized as security for operation projects.

10. Short-term debt (continued)

(a) Credit facilities (continued)

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at prime plus 0.15% or Bankers' Acceptance of a stamping fee plus 110 basis points (1.10% per annum). The uncommitted demand facility bears an interest rate at the lower of prime minus 0.10% or Bankers' Acceptance of a stamping fee plus 90 basis points (0.90% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The amount of short-term debt drawn on the credit facilities consists of:

	2011	2010
	$	$
Uncommitted demand facility	**25,000**	25,000
364-day committed revolving credit facility	**15,000**	15,000
	40,000	40,000

(b) Ontario Infrastructure Projects Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Solar business. The funding is available for up to 5 years from the date that the agreement was signed.

As at December 31, 2011, the Corporation has utilized $4,186 of the $90,000 financing facility, of which $980 was transferred to a long-term debenture. Each advance bears interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2011 was 1.74% and interest expense for the year was $13.

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the unadvanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010 and subsequently from the date of the draw of any such funds until the earlier of the facility termination date October 15, 2015 or the full advance of the committed amount. Infrastructure Ontario financing is secured by the assets of the Solar business. The financial covenants require a debt service coverage ratio of 1:1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher.

11. Long-term debt

(a) Bank term loan

The bank term loan of $50,000 is a 5 year fixed rate term loan with a Canadian Chartered Bank which bears interest at an annual rate of 5.08%. It is a non-amortizing loan with repayment at the end of the contracted term, February 26, 2013. The financial covenants require a total debt to capitalization ratio of no greater than 0.60:1, and to maintain an interest coverage ratio of no less than 1.25:1.

Interest expense relating to the bank term loan for the year ended December 31, 2011 was $2,540 (2010 - $2,540).

11. Long-term debt (continued)

(b) Debentures payable

	2011	2010
	$	$
6.45% unsecured debentures due August 15, 2012, interest payable in arrears semi-annually on August 15 and February 15	**124,489**	123,765

In August 2002, the four predecessor corporations (Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc., Richmond Hill Hydro Inc. and Barrie Hydro Distribution Inc.) raised gross proceeds of $125,000 through a private placement offering. These predecessor corporations were four of five LDCs that participated in the Electricity Distributors Finance Corporation ("EDFIN") 10 Year Debenture Issue (Series 2002-1) that was offered on a private placement. EDFIN is a specific purpose corporation managed by MEARIE Management Inc., for the purpose of providing the LDCs with efficient access to the debt capital markets. Each LDC has executed a debenture which is a direct and unsecured obligation of the LDC. The LDC's obligations are several and not joint, and each LDC is liable for its own obligation and not that of any other LDC.

The debentures are recorded at amortized cost, using the effective interest method. Interest expense relating to the debentures payable was $8,737 (2010 - $8,737) which included $724 (2010 - $674) of accretion.

The debentures are subject to a financial covenant. This covenant requires that the consolidated funded obligation does not exceed 75% of the total consolidated capitalization of the Corporation.

The Corporation has obtained a commitment for a $125,000 revolving 2 year term credit facility from a Canadian Chartered bank for the purposes of providing flexibility in refinancing the debentures payable upon maturity on August 15, 2012. Applicable interest rate and commitment fees will be determined on the date of loan execution based on the Corporation's rating as published by DBRS. Based on the Corporation's current DBRS Rating, the applicable interest rate is prime rate or Bankers' Acceptance plus 75.0 basis points (0.75% per annum). The credit facility bears a commitment fee of 15.0 basis points (0.15% per annum) on the average daily unused portions of the commitment under the credit facility.

The financial covenants require a consolidated debt to capitalization ratio of 75%, and to maintain an interest coverage ratio of no less than 1.25:1.

(c) Notes payable

	2011	2010
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	8,743
Promissory note issued to the Town of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the Town of Markham	**7,585**	7,585
Promissory note issued to the City of Barrie	**20,000**	20,000
	182,430	182,430

11. Long-term debt (continued)

(c) Notes payable (continued)

On June 1, 2004 an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On June 1, 2004 an unsecured 20 year term promissory note was issued to the Town of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the sum of $20,000. Interest for fiscal 2010 is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the Town of Markham, and the City of Barrie, with subordination and conditions. These notes have been classified as long-term as it is not the intent of the City of Vaughan, the Town of Markham, or the City of Barrie to demand repayment within the next year.

At the request of the City of Vaughan and the Town of Markham, eight quarters of interest have been deferred commencing October 1, 2006. This deferred interest will be repayable in full on October 31, 2013 and is subject to the same interest rate and conditions as the original note.

Interest of $4,853 (2010 - $4,853) on the note payable to the City of Vaughan, $4,210 (2010 - $4,210) on the note payable to the Town of Markham and $1,116 (2010 - $1,116) to the City of Barrie was charged to interest expense during the year. This includes interest on the related deferred interest balance for the City of Vaughan and the Town of Markham.

(d) Infrastructure Ontario debentures

As at December 31, 2011, the Corporation had transferred $980 of the construction financing it has accessed from Infrastructure Ontario into long-term debt maturing on November 15, 2031. The long-term debt bears interest at a rate of 4.09% per annum payable on May 15 and November 15 each year. No interest expense has been recorded in fiscal 2011.

12. Employee future benefits

The Corporation provides certain health, dental and life insurance under unfunded benefit plans on behalf of its retired employees.

The Corporation measures its accrued benefit obligation for accounting purposes every three years. The latest actuarial valuation was performed as at December 31, 2011.

A reconciliation of the Corporation's accrued benefit obligation to the amounts recorded in the financial statements is as follows:

	2011	2010
	$	$
Accrued benefit obligation	**21,832**	20,297
Unamortized transitional obligation	**(345)**	(417)
Unamortized net actuarial losses	**(5,507)**	(5,285)
Unamortized past service costs	**(715)**	(588)
Accrued benefit liability, end of the year	**15,265**	14,007

Details of the accrued benefit obligation are as follows:

	2011	2010
	$	$
Accrued benefit obligation, beginning of the year	**20,297**	16,490
Current service cost	**595**	418
Interest cost on obligation	**1,037**	951
Unamortized past service costs	**(423)**	1,261
Benefit payments	**(319)**	(428)
Actuarial losses	**645**	1,605
Accrued benefit obligation, end of the year	**21,832**	20,297

The plan expense for the year is determined as follows:

	2011	2010
	$	$
Current service cost	**595**	418
Interest cost on obligation	**1,037**	951
Amortization of transitional obligation	**72**	72
Amortization of past service costs	**(550)**	38
Amortization of net actuarial losses	**423**	292
Plan expense	**1,577**	1,771

12. Employee future benefits (continued)

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation are as follows:

	%
Discount rate	**4.50**
Rate of compensation increase	**3.50**
Medical benefits costs escalation	**5.00 - 8.00**
Dental benefits costs escalation	**5.00**

Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2011:

	Increase	Decrease
	$	$
Total service and interest cost	**293**	**(230)**
Accrued benefit obligation	**2,819**	**(2,292)**

13. Pension

The Corporation provides a pension plan to its full-time employees through OMERS, a multi-employer defined benefit plan. The Corporation incurred $3,714 (2010 - $3,150) of contribution expense during the year ended December 31, 2011.

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A common shares. The issued share capital is as follows:

	2011	2010
	$	$
Common shares	**247,183**	247,183
Class A common shares, non-voting	**4,774**	2,435
	251,957	249,618

Of the total 100,000 common shares issued 45,315 common shares are registered under Vaughan Holdings Inc. (wholly owned by the City of Vaughan), 34,185 common shares are registered under Markham Enterprises Corporation (wholly owned by the Town of Markham) and 20,500 common shares are registered under Barrie Hydro Holdings Inc. (wholly owned by the City of Barrie).

On November 23, 2010 a Subscription Agreement was signed between the Corporation and its Shareholders for new Class A common shares for the purposes of the Shareholders providing equity for the Corporation's solar business. The articles of incorporation and shareholders agreement were amended in order to proceed with the subscription agreement. The maximum amount of Class A common shares that are available under the subscription agreement is 100,000. During the year, an additional 3,899 (2010 - 4,056) of the Class A common shares were issued under the subscription agreement for an amount of $2,339 (2010 - $2,435).

Of the total 7,955 (2010 - 4,056) Class A common shares issued, 3,604 (2010 - 1,838) Class A common shares are registered under Vaughan Holdings Inc. (wholly owned by the City of Vaughan), 2,720 (2010 - 1,387) Class A common shares are registered under Markham Enterprises Corporation (wholly owned by the Town of Markham) and 1,631 (2010 - 831) Class A common shares are registered under Barrie Hydro Holdings Inc. (wholly owned by the City of Barrie).

Dividends

The Corporation has established a dividend policy to distribute a minimum dividend on the common shares of 50% of the prior year net income with consideration given to the:

- Cash position at the beginning of the year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

In 2011, the Corporation paid a dividend on the common shares of $13,857 (2010 - $10,532).

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member's claims experience. The maximum coverage is $24,000 for liability insurance, $411,460 for property insurance and $15,000 for vehicle insurance.

16. Leases

On October 9, 2008, the Corporation entered into a 25 year lease agreement relating to its operation centre. The lease term commenced January 1, 2010 and occupancy occurred in March 2010. Upon entering into this lease arrangement, the Corporation evaluated whether substantially all of the benefits and risks of ownership related to this operation centre have been transferred to the Corporation (the lessee) in order to determine if the lease is classified and recorded as capital or operating. The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a capital lease.

The Corporation is also committed to lease agreements for various vehicles, equipment and rooftops for solar projects that have been classified as operating leases.

The annual basic rent for capital and operating leases are as follows:

	Capital $	Operating $
2012	1,430	1,348
2013	1,430	1,504
2014	1,430	1,481
2015	1,430	1,458
2016	1,430	1,458
2017 and thereafter	27,855	26,522
	35,005	33,771
Less: amounts representing interest	17,326	
	17,679	
Less: current portion of capital lease obligation	277	
Capital lease obligation	17,402	

Interest on the lease obligation during fiscal 2011 amounted to $1,171 (2010 - $1,087) based on the rate of 6.57% per annum. Amortization of the corresponding PP&E during fiscal 2011 amounted to $731 (2010 - $731) based on the straight-line method with a useful life equal to the term of the lease (25 years).

17. Contingencies and commitments

(a) *Legal claims*

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) *Ministry of Finance tax audits*

The Ministry of Finance (the "Ministry") has conducted PILs audits and issued reassessments up to and including the 2006 taxation year.

There remains an outstanding matter regarding the treatment of the RSVA for tax purposes.

There has been inconsistent practice of tax treatment of certain regulatory asset/liability accounts among LDCs across Ontario.

17. Contingencies and commitments (continued)

(b) Ministry of Finance tax audits (continued)

In accordance with OEB regulations, the Corporation has recorded the variance between amounts charged by the Corporation to its customers (at the OEB prescribed rates) and the costs charged to the Corporation for electricity, market services and transmission services, namely retail settlement variances, as regulatory assets or liabilities on the financial statements. Similar treatment has been followed for tax purposes. The Ministry is questioning this treatment of the RSVA for tax purposes and is suggesting that RSVA liabilities may be considered income for tax purposes.

The Ministry is currently reviewing the treatment of RSVA for tax purposes on a province wide basis. The impact of a tax ruling may result in a reassessment of taxes payable which could have an impact on results, financial position and cash flows in the future. The outcome of the Ministry's review is not determinable and as such, amounts will be recorded as necessary.

(c) Commitments

As at December 31, 2011, the Corporation has entered into agreements for capital projects and is committed to making payments of $14,963 in 2012.

18. Financial instruments and risk management

(a) Recognition and measurement

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 2(c).

The Corporation's carrying value and fair value of financial instruments are as follows:

		2011		2010
Description	**Carrying value**	**Fair value**	Carrying value	Fair value
	$	**$**	$	$
Assets				
Cash	**-**	**-**	8,568	8,568
Accounts receivable (net of allowance for doubtful accounts)	**86,933**	**86,933**	69,366	69,366
	86,933	**86,933**	77,934	77,934
Liabilities				
Bank indebtedness	**8,039**	**8,039**	-	-
Accounts payable and accrued liabilities	**116,109**	**116,109**	105,339	105,339
Customers' deposits	**13,035**	**13,035**	13,549	13,549
Due to related parties	**11,103**	**11,103**	12,214	12,214
Short-term debt	**40,000**	**40,000**	40,000	40,000
Infrastructure Ontario financing	**3,206**	**3,206**	827	827
Bank term loan	**50,000**	**51,829**	50,000	52,529
Debentures payable	**124,489**	**130,509**	123,765	131,326
Notes payable	**182,430**	**226,432**	182,430	207,468
Infrastructure Ontario debentures	**980**	**980**	-	-
	549,391	**601,242**	528,124	563,252

18. Financial instruments and risk management (continued)

(a) Recognition and measurement (continued)

The fair value of financial instruments has been calculated using the market interest rates as at December 31, adjusted for the Corporation's risk rating.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(c) Credit risk

The Corporation's primary source of credit risks to its accounts receivable result from customer's failing to discharge their dues for electricity consumed and billed. The Corporation has approximately 335,000 (2010 - 325,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $15,436 (2010 - $17,043) in accordance with OEB guidelines, reviewing Dun & Bradstreet (D&B) reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for $4,500 (2010 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2011		2010	
	Total		Total	
	$	**$**	$	$
Less than 30 days	**72,968**	**83**	55,435	78
30 - 60 days	**7,992**	**9**	8,493	12
61 - 90 days	**4,426**	**5**	3,434	5
Greater than 91 days	**3,018**	**3**	4,082	5
Total outstanding	**88,404**	**100**	71,444	100
Less: allowance for doubtful accounts	**(1,471)**	**(2)**	(2,078)	(3)
	86,933		69,366	

As at December 31, 2011, there was no significant concentration of credit risk with respect to any class of financial assets.

18. Financial instruments and risk management (continued)

(d) *Interest rate risk*

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short term borrowing may expose the Corporation to short term interest rate fluctuations as follows:

	2011	2010
364 day revolving facility		
Prime based loans	**PR*+0.15% p.a.**	PR*+0.15% p.a.
Bankers Acceptances	**SF*+1.10% p.a.**	SF*+1.10% p.a.
Demand facility		
Prime based loans	**PR*–0.10% p.a.**	PR*–0.10% p.a.
Bankers acceptances	**SF*+0.90% p.a.**	SF*+0.90% p.a.
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	Floating rate p.a.

Note: PR - Prime Rate, SF* - Stamping Fee*

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points) would increase or decrease the annual interest expense by approximately $420.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. These interest rate fluctuations could impact the level of interest income earned by the Corporation.

(e) *Liquidity risk*

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts. The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with financial liabilities are as follows:

			2011			2010
Maturity period	**Principal ***	**Interest**	**Total**	Principal *	Interest	Total
	$	**$**	**$**	$	$	$
Less than 1 year	**255,450**	**8,158**	**263,608**	117,553	-	117,553
1-5 years	**106,511**	**10,823**	**117,334**	231,327	22,159	253,486
6-10 years	**225**	**136**	**361**	-	-	-
Over 10 years	**166,641**	**115,195**	**281,836**	166,102	124,353	290,455
	528,827	**134,313**	**663,139**	514,982	146,512	661,494

* The principal includes $511 (2010 - $1,235) of deferred issuing cost amortization

18. Financial instruments and risk management (continued)

(f) Hedging/Derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes.
The Corporation has not entered into any such transactions during the year.

19. Capital disclosures

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the distribution business;

(ii) Ensure compliance with various covenants related to its short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable and Infrastructure Ontario debentures;

(iii) Consistently maintain a high credit rating for the Corporation;

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB;

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning; and

(vi) Deliver appropriate financial returns to shareholders.

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2011 is as follows:

	2011	2010
	$	$
Shareholders' equity		
Share capital (Note 14)	**251,957**	249,618
Retained earnings	**53,446**	36,999
Total equity	**305,403**	286,617
Short-term debt		
Short-term debt (Note 10(a))	**40,000**	40,000
Infrastructure Ontario financing (Note 10(b))	**3,206**	827
Long-term debt		
Bank term loan (Note 11(a))	**50,000**	50,000
Debentures payable (Note 11(b))	**124,489**	123,765
Notes payable (Note 11(c))	**182,430**	182,430
Infrastructure Ontario debentures (Note 11(d))	**980**	-
Total debt	**401,105**	397,022
Total capital	**706,508**	683,639

As at December 31, 2011, the Corporation was in compliance with covenants related to its short-term debt, bank term loan and debentures payable. The Corporation has received a waiver with respect to the current ratio covenant calculation as at December 31, 2011 on its Infrastructure Ontario financing and Infrastructure Ontario debentures covenants. Details relating to covenants are disclosed in Note 10 and Note 11.

The Corporation is within the debt and equity requirements of the OEB.

The Corporation's dividend policy is disclosed in Note 14.

20. Corporate income taxes

The provision for PILs is comprised of the following:

	2011	2010
	$	$
Current income taxes	**4,778**	10,527
Future income liabilities	**444**	61
	5,222	10,588

(a) Current taxes

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is provided as follows:

	2011	2010
	$	$
Income from operations before PILs	**35,526**	37,055
Statutory Canadian federal and provincial income tax rates	**28.25%**	31.00%
Expected tax provision on income at statutory rates	**10,036**	11,487
Increase (decrease) in income taxes resulting from timing differences		
Amortization/CCA differences	**(3,025)**	(2,776)
Post employment benefits	**355**	611
Eligible capital expenditures	**(141)**	(166)
Other reserves	**(262)**	368
Expenses and revenues related to regulatory assets recognized for tax purposes but capitalized for accounting purposes	**(1,055)**	604
Other	**(730)**	569
Permanent differences	**44**	(109)
Provision for PILs	**5,222**	10,588

20. Corporate income taxes (continued)

(b) Future income tax assets

Future income tax assets of $49,533 (2010 - $54,539), and a corresponding regulatory liability of $49,533 (2010 - $54,539) were recorded as at December 31, 2011. Significant components of the Corporation's future income tax assets are as follows:

	2011	2010 (Restated)
	$	$
Employee future benefits	**4,770**	4,377
Property, plant, equipment and intangible assets	**43,820**	47,687
Smart meter and other regulatory revenues/costs deferred	**328**	1,750
Other deductible temporary differences	**615**	725
	49,533	54,539

When adjusting the future income tax assets for the year ended December 31, 2011, it was determined that there was an error in the December 31, 2010 future income tax balance arising primarily from the tax treatment of the capital lease for the Corporation's operation centre as well as stranded mechanical meters. This resulted in an increase in the future income tax balance of $1,226 at December 31, 2010 and a corresponding increase in the future income taxes regulatory liability account. The prior year's comparative figures have been restated to reflect this correction in the balance sheet accounts. There was no impact on the December 31, 2010 net earnings and comprehensive income for the year or retained earnings.

(c) Future income tax liabilities

Future income tax liabilities of $505 were recorded as at December 31, 2011. The future tax liabilities relate to taxable temporary differences. This amount is not offset by a regulatory asset, as it relates specifically to the Corporation's non-regulated solar business.

21. Net change in non-cash operating working capital

	2011	2010
	$	$
Accounts receivable	**(17,567)**	4,267
Unbilled revenue	**1,838**	(4,047)
Income taxes recoverable	**-**	1,525
Inventories	**(217)**	819
Prepaids and other	**(317)**	(137)
Accounts payable and accrued liabilities	**4,436**	(7,372)
Current portion of customer deposits	**(473)**	478
Income taxes payable	**(3,177)**	1,588
Due to related parties	**(1,111)**	165
	(16,588)	(2,714)

22. Net interest expense

	2011	2010
	$	$
Interest expense	**24,291**	22,421
Interest income	**(470)**	(407)
	23,821	22,014

23. Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(a) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

(b) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(c) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

24. Subsequent event

On March 6, 2012, the Corporation entered into a share purchase agreement with The Corporation of the Town of Collingwood to purchase 50% of the issued and outstanding shares of Collingwood Utility Services Corp. for a purchase price of $8,000, which is subject to review and approval by the OEB.

25. Comparatives

In certain instances, the prior year information presented for comparative purposes has been reclassified to conform to the financial statement presentation adopted for the current year.

Schedule 17

FINANCIAL STATEMENTS – 2012 FORECAST (BRIDGE YEAR) – CONSOLIDATED AND SEGMENTED

POWERSTREAM INC.

Pro-Forma Income Statement (Consolidated)
For the period ended December 31, 2012
($000's)

	2012 Forecast
REVENUE	
Sale of Energy	774,400
Distribution Revenue	159,300
Other Revenue	10,900
Total Revenue	**944,600**
Cost of Power	774,400
Margin	**170,200**
EXPENSES	**84,800**
EBITDA	**85,400**
Amortization	32,600
Interest	24,200
EBT	**28,600**
Amounts in lieu of income taxes	2,500
Net Earnings	**26,100**

POWERSTREAM SOLAR.

Pro-Forma Income Statement
For the period ended December 31, 2012
($000's)

	2012 Forecast
REVENUE	
Renewable Generation Revenue	1,800
EXPENSES	**2,900**
EBITDA	**(1,100)**
Amortization	600
Interest	400
EBT	**(2,100)**
Provision for income taxes	(3,600)
Deferred taxes	2,900
Net Earnings	**(1,400)**

POWERSTREAM
CONSERVATION DEMAND MANAGEMENT

Pro-Forma Statement of Operations
For the period ended December 31, 2012
($000's)

	2012 Forecast
REVENUE	
Revenue (OPA funding)	19,600
EXPENSES (Program Costs)	**19,600**
EBT	**0**
Income taxes	0
Net Earnings	**0**

Schedule 18

FINANCIAL STATEMENTS – 2013 FORECAST (TEST YEAR) – CONSOLIDATED AND SEGMENTED

POWERSTREAM INC.

Pro-Forma Income Statement (Consolidated)
For the period ended December 31, 2013
($000's)

	2013 Forecast
REVENUE	
Sale of Energy	822,800
Distribution Revenue	170,700
Other Revenue	11,300
Total Revenue	**1,004,800**
Cost of Power	822,800
Margin	**182,000**
EXPENSES	**89,000**
EBITDA	**93,000**
Amortization	34,700
Interest	25,000
EBT	**33,300**
Amounts in lieu of income taxes	700
Net Earnings	**32,600**

POWERSTREAM SOLAR.

Pro-Forma Income Statement
For the period ended December 31, 2013
($000's)

	2013 Forecast
REVENUE	
Renewable Generation Revenue	10,700
EXPENSES	**3,900**
EBITDA	**6,800**
Amortization	3,400
Interest	1,900
EBT	**1,500**
Provision for income taxes	(5,800)
Deferred taxes	6,100
Net Earnings	**1,200**

POWERSTREAM
CONSERVATION DEMAND MANAGEMENT

Pro-Forma Statement of Operations
For the period ended December 31, 2013
($000's)

	2013 Forecast
REVENUE	
Revenue (OPA funding)	28,500
EXPENSES (Program Costs)	**28,500**
EBT	**0**
Income taxes	0
Net Earnings	**0**

Schedule 19

FINANCIAL STATEMENTS – RECONCILIATION OF REGULATORY & STATUTORY REPORTS

RECONCILIATION OF AUDITED FINANCIAL STATEMENTS AND APPLICATION

1. HISTORICAL YEAR (2009)

Table 1 reconciles PowerStream's 2009 Audited Financial Statements to information for the 2009 Historical Year that is provided in this Application:

Table 1 – Comparison of Financial Statement to Rate Application

Statement of Income and Retained Earnings	2009 Financial Statement $000	Historical Year 2009 $000	Difference, $000	Table
Sale of Energy	621,719	621,719	0	
Distribution sales	146,076	143,066	(3,010)	**2**
Other revenue	9,889	10,055	166	**3**
	777,684	**774,840**	(2,844)	
Cost of Power Purchased	621,719	621,179	0	
Margin	**155,965**	**153,121**	(2,844)	
Operating Expenses	62,601	59,677	(2,924)	**4**
Earnings before amortization, interest and income taxes	93,364	93,444	80	
Amortization	42,125	41,855	(270)	**5**

Item	2009 Fin. Statements, $000	2009 in Rate Application $000	Difference, $000	Table
Capital Assets	605,378	539,488	(65,890)	***6***
Accumulated Amortization	596,533	595,854	(679)	***7***

Table 2 reconciles Distribution Revenue in the 2009 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 2 –Distribution Revenue (2009)

Item	2009 FS, $000	2013 Rate Application $000	Notes
Distribution Revenue	**146,076**		
Reconciling Items			
Adjustment to distribution revenue		(1,756)	Distribution Revenue in Financial statements includes additional charges, mainly from Smart Meter recovery
Retail Services Revenue/STR services		(414)	Included as Distribution Revenue in Financial statements, but is part of Revenue Offsets
SSS Admin Charge Revenue		(840)	
Total Adjustments		**(3,010)**	
Total in 2013 EDR model		**143,066**	

Table 3 reconciles Other Revenue in the 2009 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 3 –Other Revenue (2009)

Item	2009 FS, $000	2009 in Rate Application $000	Notes
Other Revenue	**9,889**		
Reconciling Items			
Revenue and expense from non-utility operations, including Solar[1]		(1,664)	Defined as "Other revenue – unclassified" in USoA
Interest Income		579	Netted with interest expense in FS
Retail Services Revenue/STR revenue		414	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		840	
Rounding in Financial Statements		(3)	
Total adjustments		**166**	
Total in 2013 EDR model		**10,055**	

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[1] Including accounts 4375 Revenue from non-utility operations,4380 Expense from Non-utility operations, 4385 Non-utility rental income

Table 4 reconciles OM&A in the 2009 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 4 – OM&A (2009)

Item	2009 FS, $000	2009 Adjustments in 2013 Rate Application $000	Notes
Total OM&A	**62,601**		
Sponsorships		(227)	Sponsorships not recovered through distribution rates
Charitable contributions		(101)	Donations not recovered through distribution rates
Other Distribution Expenses		(1,593)	Ontario Capital Tax is removed, since it is calculated as part of PILs model
Non-distribution expenses		(1,003)	Mainly expenses of Solar business -Excluded from EDR model
Total adjustments		**(2,924)**	
Total in 2013 EDR model		**59,677**	

The reconciliation of Amortization expenses as reported in the 2009 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in Table 5.

Table 5 – Amortization expense (2009)

Item	2009 Fin. Statements $000	2009 Adjustments in 2013 Rate Application $000	Notes
Amortization expense	**42,125**		
Reconciling items			
		(232)	Adjustment to remove FMV of Aurora
		(38)	Non-Distribution Assets
Total Adjustments		(270)	
Total in 2013 EDR model		**41,855**	

A reconciliation of Capital Assets as reported in the 2009 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in the table below:

Table 6 – Capital Assets (2009)

Item	2009 Fin. Statements $000	Adjustments in 2013 Rate Application $000	2009 in Rate model $000	Notes
Gross Assets	**1,455,884**			
Reconciling Items				
		(59,227)		WIP excluded from NFA for Rate Base Calculation
		123		Adjustment to remove FMV of Aurora Assets
		(974)		Non-Distribution Assets
Total Adjustments		**(60,078)**		
Total Gross Assets in 2013 EDR model			**1,395,806**	
Contributed Capital	**(253,973)**			
Total Adjustments		(6,662)		Adjustment to remove FMV of Aurora Assets
		171		Remove non-distribution assets
Contributed Capital in 2013 EDR model			**(260,464)**	
Gross Assets Net of CC	**1,201,911**		**1,135,342**	

A reconciliation of Accumulated Amortization as reported in the 2009 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in the table below:

Table 7 – Accumulated Amortization (2009)

Item	2009 Fin. Statements $000	Adjustments in 2013 Rate Application $000	2009 in Rate model $000	Notes
Accumulated Amortization	**596,533**			
		(746)		Accumulated adjustment for FMV of Aurora's assets
		(112)		Non-distribution items removed from Rate Base[2]
		179		Accumulated adjustment for Land rights
Total Adjustments		**(679)**		
Total Amortization in 2013 EDR model			**595,854**	

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[2] Street Lighting and Sentinel lighting rental units

2. HISTORICAL YEAR (2010)

Table 1 reconciles PowerStream's 2010 Audited Financial Statements to information for the 2010 Historical Year that is provided in this Application:

Table 1 – Comparison of Financial Statement to Rate Application

Statement of Income and Retained Earnings	2010 FS $000	Historical Year 2010 $000	Difference, $000	Table
Sale of Energy	691,318	691,318	0	
Distribution sales	155,841	148,580	(7,281)	**2**
Other revenue	9,229	8,945	(284)	**3**
	856,388	**848,843**	(7,545)	
Cost of Power Purchased	691,318	691,318	0	
Margin	**165,070**	**157,525**	(7,545)	
Operating Expenses	59,746	56,838	(2,908)	**4**
Earnings before amortization, interest and income taxes	105,324	100,687	(4,637)	
Amortization	46,255	45,971	(284)	**5**

Item	2010 Fin. Statements, $000	2010 in Rate Application $000	Difference, $000	Table
Capital Assets	646,239	613,156	(33,083)	***6***
Accumulated Amortization	619,451	616,874	(2,577)	***7***

Table 2 reconciles Distribution Revenue in the 2010 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 2 –Distribution Revenue (2010)

Item	2010 FS, $000	2010 Rate Application $000	Notes
Distribution Revenue	**155,841**		
Reconciling Items			
Adjustment to distribution revenue		(6,033)	Distribution Revenue in Financial statements includes additional charges, mainly from Smart Meter recovery
Retail Services Revenue /STR revenues		(372)	These accounts are part of Board Approved Revenue Offsets, but are included as Distribution Revenue in Financial Statements
SSS Admin Charge Revenue		(856)	
Total Adjustments		**(7,261)**	
Total in 2013 EDR model		**148,580**	

Table 3 reconciles Other Revenue in the 2010 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 3 –Other Revenue (2010)

Item	2010 FS, $000	2010 in Rate Application $000	Notes
Other Revenue	**9,229**		
Reconciling Items			
SPC recovery		(291)	Special Service Charge – excluded from rate model as non-distribution item
Revenue and expense from non-utility operations, including Solar[3]		(1,561)	Defined as "Other revenue – unclassified" in USoA
Interest Income		342	Netted with interest expense in FS
Retail Services Revenue		372	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		856	
Rounding in Financial Statements		(2)	
Total adjustments		**(284)**	
Total in 2013 EDR model		**8,945**	

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[3] Including accounts 4375 Revenue from non-utility operations,4380 Expense from Non-utility operations, 4385 Non-utility rental income

Table 4 reconciles OM&A in the 2010 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 4 – OM&A (2010)

Item	2010 FS, $000	2010 Adjustments in 2013 Rate Application $000	Notes
Total OM&A	**59,746**		
Sponsorships		(276)	Sponsorships not recovered through distribution rates
Charitable contributions		(43)	Donations not recovered through distribution rates
Other Distribution Expenses		(561)	Ontario Capital Tax is removed, since it is calculated as part of PILs model
SPC expense		(277)	Excluded from EDR model
Non-distribution expenses		(1,751)	Mainly Solar - Excluded from EDR model
Total adjustments		**(2,908)**	
Total in 2013 EDR model		**56,838**	

The reconciliation of Amortization expenses as reported in the 2010 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in Table 5.

Table 5 – Amortization expense (2010)

Item	2010 Fin. Statements $000	2010 Adjustments in 2013 Rate Application $000	Notes
Amortization expense	**46,255**		
Reconciling items		(237)	Adjustment to remove FMV of Aurora's assets
		(47)	Non-distribution assets
Total Adjustments		**(284)**	
Total in 2013 EDR model		**45,971**	

A reconciliation of Capital Assets as reported in the 2010 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in the table below:

Table 6 – Capital Assets (2010)

Item	2010 Fin. Statements $000	Adjustments in 2013 Rate Application $000	2010 in Rate model $000	Notes
Gross Assets	**1,542,700**			
Reconciling items:				
		(26,786)		WIP excluded from NFA for Rate Base Calculation
		123		Adjustment to remove FMV of Aurora Assets
		(2,653)		Non-distribution assets
Total Adjustments		**(29,316)**		
Total Gross Assets in 2013 EDR model			**1,513,384**	
Contributed Capital	**(277,010)**			
		(6,662)		Adjustment to remove FMV of Aurora Assets
		319		Contributed capital for Non-distribution assets
Total Adjustments		(6,343)		
Contributed Capital in 2013 EDR model			**(283,353)**	
Gross Assets Net of CC	**1,265,690**	**(35,659)**	**1,230,031**	

A reconciliation of Accumulated Amortization as reported in the 2010 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in the table below:

Table 7 – Accumulated Amortization (2010)

Item	2010 Fin. Statements $000	Adjustments in 2013 Rate Application $000	2010 in Rate model $000	Notes
Accumulated Amortization	**619,451**			
		(1,000)		Accumulated adjustment for FMV of Aurora's assets
		(1,577)		Non-distribution items removed from Rate Base[4]
Total Adjustments		**(2,577)**		
Total Amortization in 2013 EDR model			**616,874**	

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[4] Street Lighting and Sentinel lighting rental units

3. HISTORICAL YEAR (2011 CGAAP)

Table 1 reconciles PowerStream's 2011 Audited Financial Statements (CGAAP) to information for the 2011 Historical Year (CGAAP) that is provided in this Application.

The 2011 MIFRS Financial Statements are expected to be available in late summer of 2012.

Table 1 – Comparison of Financial Statement to Rate Application

Statement of Income and Retained Earnings	2011 Financial Statement $000	Historical Year 2011 (CGAAP) $000	Difference, $000	Table
Sale of Energy	751,457	751,457	0	
Distribution sales	160,914	154,615	(6,299)	**2**
Other revenue	10,052	9,167	(885)	**3**
	922,423	**915,239**	(7,184)	
Cost of Power Purchased	751,457	751,457	0	
Margin	**170,966**	**163,782**	(7,184)	
Operating Expenses	65,492	62,087	(3,405)	**4**
Earnings before amortization, interest and income taxes	105,474	101,695	(3,779)	
Amortization	46,127	45,756	(371)	**5**

Item	2011 Fin. Statements, $000	2011 in Rate Application $000	Difference, $000	Table
Capital Assets	696,893	651,909	(44,984)	***6***
Accumulated Amortization	664,860	661,892	(2,968)	***7***

Table 2 reconciles Distribution Revenue in the 2011 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 2 –Distribution Revenue (2011)

Item	2011 FS, $000	2013 Rate Application, $000	Notes
Distribution Revenue	**160,914**		
Reconciling Items			
Adjustments to distribution revenue			
		(5,284)	Smart Meter Transfer – included in FS
		201	Other (Tax Change , Power Diversion)
Retail Services Revenue		(327)	These accounts are part of Board Approved Revenue Offsets, but are included as Distribution Revenue in Financial Statements
SSS Admin Charge Revenue		(889)	
Total Adjustments		**(6,299)**	
Total in 2013 EDR model		**154,615**	

Table 3 reconciles Other Revenue in the 2011 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 3 –Other Revenue (2011)

Item	2011 FS, $000	2011 in Rate Application $000	Notes
Other Revenue	**10,052**		
Reconciling Items			
Revenue and expense from non-utility operations, including Solar[5]		(2,246)	Defined as "Other revenue – unclassified" in USoA
Interest Income		145	Netted with interest expense in FS
Retail Services Revenue		327	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		889	
Total adjustments		**(885)**	
Total in 2013 EDR model		**9,167**	

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[5] Including accounts 4375 Revenue from non-utility operations,4380 Expense from Non-utility operations, 4385 Non-utility rental income

Table 4 reconciles OM&A in the 2011 Audited Financial Statements and as presented in PowerStream's 2013 EDR application:

Table 4 – OM&A (2011)

Item	2011 FS, $000	2011 Adjustments in 2013 Rate Application $000	Notes
Total OM&A	**65,492**		
Sponsorships		(304)	Sponsorships not recovered through distribution rates
A&G Expenses		(213)	Expenses related to M&A preparation - not recovered through distribution rates
Charitable contributions		(298)	Donations not recovered through distribution rates
Non-distribution expenses		(2,590)	Mainly Solar - Excluded from EDR model
Total adjustments		**(3,405)**	
Total in 2013 EDR model		**62,087**	

The reconciliation of Amortization expenses as reported in the 2011 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in Table 5.

Table 5 – Amortization expense (2011)

Item	**2011 Fin. Statements $000**	**2011 Adjustments in 2013 Rate Application $000**	**Notes**
Amortization expense	**46,127**		
Reconciling items			
		(240)	Adjustment to remove FMV of Aurora's assets
		(50)	Non-distribution assets
		(81)	Depreciation for Solar included in Financial statements
Total Adjustments		**(371)**	
Total in 2013 EDR model		**45,756**	

A reconciliation of Capital Assets as reported in the 2011 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in the table below:

Table 6 – Capital Assets (2011)

Item	2011 Fin. Statements $000	Adjustments in 2013 Rate Application $000	2011 in Rate model $000	Notes
Gross Assets	**1,662,625**			
Reconciling items:				
		(31,958)		Work in Progress
		123		Adjustment to remove FMV of Aurora
		(1,760)		Non-Distribution
		(8,338)		Remove Solar Assets
		(41,925)		
Total Gross Assets in 2013 EDR model			**1,620,700**	
Contributed Capital	**(300,872)**			
		(6,662)		Adjustment to remove FMV of Aurora
		636		Non-Distribution Assets
Total Adjustments		(6,026)		
Contributed Capital in 2013 EDR model			**(306,898)**	
Gross Assets Net of CC	**1,361,753**	**(47,951)**	**1,313,802**	

A reconciliation of Accumulated Amortization as reported in the 2011 Audited Financial Statements and as provided in PowerStream's 2013 EDR application is presented in the table below:

Table 7 – Accumulated Amortization (2011)

Item	2011 Fin. Statements $000	Adjustments in 2013 Rate Application $000	2011 in Rate model $000	Notes
Accumulated Amortization	**664,860**			
		(2,682)		Accumulated Depreciation FMV of Aurora's assets
		(205)		Non-distribution items removed from Rate Base[6]
		(81)		Amortization of Solar Assets included in Financial Statements
Total Adjustments		**(2,968)**		
Total Amortization in 2013 EDR model			**661,892**	

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[6] Street Lighting and Sentinel lighting rental units

4. BRIDGE YEAR (2012)

Table 1 compares PowerStream's 2012 Pro-forma Income Statement to information for the 2012 Bridge Year that is provided in this Application:

Table 1 – Reconciliation of Financial Statement to Rate Application

Statement of Income and Retained Earnings	**2012 FS $000**	**Bridge Year $000**	**Difference, $000**	**Table/Note**
Revenues				
Sale of Energy	774,400	819,092	44,692	Financial Statements use original 2012 budget[7]
Distribution sales	159,300	160,263	*963*	*2*
Other revenue	10,900	8,799	*(2,101)*	*3*
	944,600	**988,154**	*43,554*	
Cost of Power Purchased	774,000	819,092	*44,692*	
Margin	**170,200**	**169,062**	*(1,138)*	
Operating Expenses	84,800	81,596	*(3,204)*	*4*
Earnings before amortization, interest and income taxes	85,400	87,466	*2,066*	
Amortization	32,600	32,094	*(506)*	*5*

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[7] The Cost of Power forecast in Rate Application is based on the most recent prices, as per Navigant report of April 19, 2012

Table 2 reconciles Distribution Revenue in the 2012 Pro-Forma Income Statement and as presented in PowerStream's 2013 EDR application:

Table 2 –Distribution Revenue (2012)

Item	2012 FS, $000	2012 in Rate Application $000	Notes
Distribution Revenue	**159,300**		
Adjustment to distribution revenue		1,839	Forecast updated due to the changes in load forecast and distribution rates
		449	Pro forma FS include provision for deferred IFRS and PST savings to be recognized
Retail Services Revenue / STR		(392)	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		(916)	
Total Adjustments		**963**	
Total in 2009 EDR model		**160,263**	

Table 3 reconciles Other Revenue in the 2012 Pro-Forma Income Statement and as presented in PowerStream's 2013 EDR application.

Table 3 –Other Revenue (2012)

Item	2012 FS, $000	2012 in Rate Application $000	Notes
Other Revenue	**10,900**		
Reconciling Items			
Misc. Service revenues / rent from electric utility		163	Forecast updates , mainly for the damage claims revenues
Revenue and expense from non-utility operations[8]		(3,572)	Defined as "Other revenue – unclassified" in USoA; mainly Solar
Retail Services Revenue		392	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		916	
Total adjustments		**(2,101)**	
Total in 2013 EDR model		**8,799**	

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[8] Including accounts 4375 Revenue from non-utility operations,4380 Expense from Non-utility operations, 4385 Non-utility rental income

Table 4 reconciles OM&A in the 2012 Pro-Forma Income Statement and as presented in PowerStream's 2013 EDR application.

Table 4 – OM&A (2012)

Item	**2012 FS, $000**	**Adjustments in Rate Application, $000**	**Notes**
Total OM&A	**84,800**		
Adjustments to remove non-distribution expenses:			
Sponsorships		(308)	Sponsorships not recovered through distribution rates
A&G Expenses		(2,843)	Cost of Joint services included in OM&A in FS, but removed from OM&A in EDR model
Charitable contributions		(70)	Donations not recovered through distribution rates
		17	Rounding in FS
Total adjustments		**(3,204)**	
Total in 2013 EDR model		**81,596**	

The reconciliation of Amortization expenses as reported in the 2012 Pro-Forma Income Statement and as provided in PowerStream's 2013 EDR application is presented in Table 5.

Table 5 – Amortization expense (2012)

Item	2012 Fin. Statement $000	Adjustments in 2013 Rate Application $000	Notes
Amortization expense	**32,600**		**Forecast**
Reconciling items		(244)	Adjustment to remove FMV of Aurora's assets
		54	Street-light non-distribution assets.
		94	WIP application
		(410)	Calculation of Amortization in Pro-forma FS is done using "average" amortization rate, while Rate Application calculates amortization on a more detailed basis.
Total Adjustments		**(506)**	
Total in 2009 EDR model		**32,094**	

5. TEST YEAR (2013)

Table 1 reconciles PowerStream's 2013 Pro-forma Income Statement to information for the 2013 Test Year that is provided in this Application:

Table 1 – Reconciliation of Financial Statement to Rate Application

Statement of Income and Retained Earnings	**2013 Income Statement, $000**	**2013 Test Year, $000**	**Difference, $000**	**Tables**
Revenues				
Sale of Energy	822,800	857,780	34,980	Financial Statements use original Cost of Power Forecast[9]
Distribution sales	170,700	169,488	(1,212)	**2**
Other revenue	11,300	9,062	(2,238)	**3**
	1,004,800	**1,036,330**	**31,530**	
Cost of Power Purchased	822,800	857,780	34,980	
Margin	**182,000**	**178,550**	**(3,450)**	
Operating Expenses	89,000	85,701	**(3,299)**	**4**
Earnings before amortization, interest and income taxes	93,000	92,849	**(151)**	
Amortization	34,700	35,043	**343**	**5**

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[9] The Cost of Power forecast in Rate Application is based on the most recent prices, as per Navigant report of April 19, 2012

Table 2 reconciles Distribution Revenue in the 2013 Pro-Forma Income Statement and as presented in PowerStream's 2013 EDR application:

Table 2 –Distribution Revenue (2013)

Item	2013 FS, $000	2013 Rate Application $000	Notes
Distribution Revenue	**170,700**		As based on the original estimate of Base Revenue Requirement
Reconciling Items			
		(1,212)	Net Change in Revenue requirement
	Total Adjustments	**(1,212)**	
	Total in 2013 EDR model	**(169,488)**	**Revised Base Revenue Requirement**

Table 3 reconciles Other Revenue in the 2013 Pro-Forma Income Statement and as presented in PowerStream's 2013 EDR application:

Table 3 –Other Revenue (2013)

Item	**2013 FS, $000**	**2013 Rate Application $000**	**Notes**
Other Revenue	**11,300**		
Reconciling Items			
Misc. Service revenues / rent from electric utility		99	Forecast updates , mainly for the damage claims revenues
Revenue and expense from non-utility operations[10]		(3,669)	Defined as "Other revenue – unclassified" in USoA; mainly Solar
Retail Services Revenue		400	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		932	
Total adjustments		**(2,238)**	
Total in 2013 EDR model		**9,062**	

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[10] Including accounts 4375 Revenue from non-utility operations,4380 Expense from Non-utility operations, 4385 Non-utility rental income

Table 4 reconciles OM&A in the 2013 Pro-Forma Income Statement and as presented in PowerStream's 2013 EDR application:

Table 4 – OM&A (2013)

Item	**2013 FS, $000**	**Adjustments in 2013 Rate Application $000**	**Notes**
Total OM&A	**89,000**		
Reconciling Items			
Sponsorships		(308)	Sponsorships not recovered through distribution rates
A&G Expenses		(2,928)	Cost of Joint services included in OM&A in FS, but removed from OM&A in EDR model
Charitable contributions		(70)	Donations not recovered through distribution rates
		7	Rounding in FS
Total adjustments		**(3,299)**	
Total in 2013 EDR model		**85,701**	

The reconciliation of Amortization expenses as reported in the 2013 Pro-Forma Income Statement and as provided in PowerStream's 2013 EDR application is presented in Table 5.

Table 5 – Amortization expense (2013)

Item	2013 FS $000	Adjustments in 2013 Rate Application $000	Notes
Amortization expense	**34,700**		
Reconciling items			
		740	Calculation of Amortization in Pro-forma FS is done using "average" amortization rate, while Rate Application calculates amortization on a more detailed basis.
		(135)	WIP
		(245)	Adjustment to remove FMV of Aurora assets
		(17)	Non-distribution assets
Total Adjustments		**343**	
Total in 2013 EDR model		**35,043**	

Schedule 20

RATING AGENCY REPORTS

STANDARD
&POOR'S

Global Credit Portal®
RatingsDirect®

March 1, 2012

Electricity Distributors Finance Corp.

Primary Credit Analyst:
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Table Of Contents

Electricity Distributors Finance Corp.

Major Rating Factors

Strengths:

- Stable, regulated cash flows
- Limited exposure to commodity price and volume risk
- Low-risk monopoly

None

Weaknesses:

- Significant financial risk profiles of entities supporting the debentures

Rationale

The 'A' issue-level rating on Ontario-based Electricity Distributors Finance Corp. (EDFIN) reflects Standard & Poor's Ratings Services' assessment of the risk profile of its least creditworthy participant. EDFIN is a special-purpose entity that acts as a financial conduit for participating local distribution companies (LDCs) in the Province of Ontario (AA-/Stable/A-1+). It has no assets or other liabilities itself. The rating on the company's C$175 million, 6.45% unsecured debentures series 2002-1 outstanding reflects our view of the least creditworthy participant supporting the debentures, because the EDFIN structure does not provide for pooled credit support. Each LDC is liable only for its obligations within the structure and has no liability for the obligations of the other. PowerStream Inc. (C$125 million) and EnWin Utilities Ltd. (C$50 million) support the C$175 million EDFIN debt obligation, which matures Aug. 15, 2012.

The 'A' rating reflects our view of both participants' excellent business risk profiles as regulated electricity distribution companies and our expectation that they will maintain their significant financial risk profiles.

Although both EDFIN participants are wholly owned municipal entities (EnWin by the City of Windsor [AA/Stable/--]); and PowerStream by the City of Vaughan [not rated], the Town of Markham (not rated), and the City of Barrie [AA/Stable/--]), the rating on the EDFIN debt reflects our view on both participants' stand-alone creditworthiness. In accordance with our criteria, we believe there is a "low" likelihood that the shareholders would provide timely and sufficient extraordinary support in a financial crisis.

Cash flow to service the EDFIN debt comes almost entirely from stable and predictable regulated electricity distribution activities. The Ontario Energy Board's (OEB) regulatory framework supports both LDCs' cash flow stability, allowing for the recovery of prudent costs and the opportunity to earn a modest return. We believe regulatory cost recovery is generally predictable. The current environment limits the LDCs' exposure to commodity risk. Although the companies must bill electricity customers for the commodity delivered, the cost is a flow-through. The LDCs have no obligation to ensure an adequate supply of electricity and are not burdened with the procurement process or power purchase agreements. Net distribution revenues are subject to modest volumetric risk, largely due to weather. The OEB continues its consultations for a renewed regulatory framework for LDCs in Ontario. It's too early to tell how this initiative will affect the ratings on LDCs in Ontario. We are also unaware of any fixed time frame for implementation. Nevertheless, we believe the overarching principle of maintaining a balance between LDCs and ratepayer interests remains strong. Each company's monopoly position in its service franchise and electricity distribution's asset-intensive and essential nature limit competitive risk, in our view. The electricity distribution business also carries relatively low operating risk.

We expect the EDFIN participants' significant financial risk profiles to stay relatively stable and financial key coverage ratios to be comparable to those of 'A' rated Ontario LDC peers. As of Sept. 30, 2011, EnWin's rolling 12-month adjusted fund from operations (AFFO) debt coverage ratio was 25%. PowerStream's AFFO debt coverage ratio was 19%, in line with our expectations. We expect both participants' cash flows to be steady and predictable at similar levels. We expect both participants will maintain their balance sheets in line with the regulatory-deemed capital structure for the foreseeable future.

In our view, repayment risk is limited; both participants are taking steps in securing sources to pay their respective portion of the EDFIN debt and have made meaningful progress to date, consistent with our expectations. We expect the regulated LDCs to continue to enjoy strong access to capital markets.

Liquidity

As a special-purpose entity, EDFIN relies on both participants' timely repayments to service and repay the C$175 million EDFIN obligations on Aug. 15, 2012. We view the EDFIN participants' liquidity adequate to cover needs (including the EDFIN debt repayments) in the near future. In our assessment, we incorporate the following factors:

- EnWin has a fully available C$75 million committed credit facility with Royal Bank of Canada (that extends to Aug. 31, 2014), which is sufficient to cover its C$50 million EDFIN debt repayment. Our estimated annual FFO of C$20 million is sufficient to cover its on-going annual maintenance capital expenditure in the next 12 months.
- PowerStream's 364-day committed revolver credit facility of C$75 million and our estimated annual FFO of C$60 million are not sufficient to cover the company's committed annual capital expenditure and C$125 million EDFIN debt repayment. However, we believe that it has a credible financing plan to address this issue within the next three months.

Accounting

The EDFIN participants prepare audited consolidated financial statements (fiscal year ended Dec. 31) and unaudited quarterly statements in accordance with Canadian generally accepted accounting principles. Both participants plan to adopt International Financial Reporting Standards effective Jan 1, 2012. We do not expect the change to affect our rating. No participant has power purchase agreement commitments or material operating leases. A third party provides pensions, and costs are expensed and recovered through rates. Standard & Poor's has materially adjusted EnWin's reported debt (including C$15 million of the intercompany debt), reflecting about C$22 million in postretirement benefit obligations. We expect the company will recover the cost of these obligations through regulated rates.

Table 1

EnWin Utilities Ltd. And PowerStream Inc.--Peer Comparison

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31, 2010--			
(Mil. C$)	**Enwin Utilities Ltd.***	**Powerstream Inc.***	**ENTEGRUS Inc.**	**London Hydro Inc.**
Rating as of March 1, 2012	NR	NR	A/Negative/--	A/Stable/--
Revenues	273.1	856.4	102.1	337.4
EBITDA	33.9	107.1	11.5	33.6
Net income from continuing operations	12.2	26.5	3.5	9.0

Table 1

EnWin Utilities Ltd. And PowerStream Inc.--Peer Comparison (cont.)

Funds from operations (FFO)	29.4	85.2	7.8	25.9
Capital expenditures	17.2	79.2	9.7	23.8
Free operating cash flow	3.8	3.2	0.6	2.0
Dividends paid	4.0	10.5	1.9	12.5
Discretionary cash flow	(0.2)	(7.3)	(1.3)	(10.5)
Cash and short-term investments	0.0	8.6	7.2	7.7
Debt	98.0	442.6	26.4	101.2
Equity	84.8	282.3	43.3	117.2
Debt and equity	182.8	724.9	69.6	218.4
Adjusted ratios				
EBITDA interest coverage (x)	5.8	4.2	6.6	6.1
FFO interest coverage (x)	5.1	4.3	5.5	5.5
FFO/debt (%)	30.0	19.2	29.7	25.6
Free operating cash flow/debt (%)	3.8	0.7	2.2	2.0
Discretionary cash flow/debt (%)	(0.2)	(1.7)	(5.1)	(10.4)
Net cash flow / capex (%)	147.1	94.2	61.0	56.3
Debt/EBITDA (x)	2.9	4.1	2.3	3.0
Total debt/debt plus equity (%)	53.6	61.1	37.8	46.3
Return on common equity (%)	15.2	9.0	8.2	7.8
Common dividend payout ratio (unadjusted; %)	18.4	39.8	54.9	27.6

*'A' debt rating on the senior unsecured debt of Electricity Distributors Finance Corp. NR--Not rated.

Table 2

EnWin Utilities Ltd.--Financial Summary

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2010**	**2009**	**2008**	**2007**	**2006**
Rating history	NR	NR	NR	NR	NR
Revenues	273.1	238.2	239.1	241.8	227.2
EBITDA	33.9	31.2	28.9	28.9	22.1
Net income from continuing operations	12.2	8.9	7.6	15.7	10.8
Funds from operations (FFO)	29.4	18.7	19.3	19.5	13.5
Capital expenditures	17.2	22.6	10.2	12.4	7.8
Dividends paid	4.0	3.3	5.0	3.0	2.0
Debt	98.0	92.0	85.5	93.7	99.5
Equity	84.8	75.8	85.5	82.0	70.0
Debt and equity	182.8	167.8	171.0	175.7	169.5
Adjusted ratios					
EBITDA interest coverage (x)	5.8	5.4	4.4	4.1	3.3
FFO interest coverage (x)	5.1	3.5	3.5	3.4	2.9
FFO/debt (%)	30.0	20.3	22.5	20.8	13.5
Discretionary cash flow/debt (%)	(0.2)	2.3	5.0	7.6	(2.4)

Table 2

EnWin Utilities Ltd.--Financial Summary (cont.)

Net cash flow/capex (%)	147.1	68.1	139.8	133.1	147.5
Debt/debt and equity (%)	53.6	54.8	50.0	53.4	58.7
Return on common equity (%)	15.2	11.0	9.0	20.7	16.7
Common dividend payout ratio (unadjusted; %)	18.4	45.2	66.2	19.1	18.6

NR--Not rated.

Table 3

Reconciliation Of EnWin Utilities Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2010--									
Enwin Utilities Ltd. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	72.9	84.8	273.1	32.4	18.7	4.0	18.8	18.8	4.0	17.2
Standard & Poor's adjustments										
Operating leases	3.1	N/A	N/A	0.3	0.3	0.3	2.9	2.9	N/A	0.1
Postretirement benefit obligations	22.0	N/A	N/A	1.2	1.2	1.7	(0.7)	(0.7)	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.4	N/A	N/A
Total adjustments	25.1	0.0	0.0	1.5	1.5	1.9	2.2	10.5	0.0	0.1
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	98.0	84.8	273.1	33.9	20.2	5.9	21.0	29.4	4.0	17.2

N/A--Not applicable.

Table 4

PowerStream Inc.--Financial Summary

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2010**	**2009**	**2008**	**2007**	**2006**
Rating history	NR	NR	NR	NR	NR
Revenues	856.4	777.7	606.2	614.8	591.9
EBITDA	107.1	94.5	73.8	80.1	76.7
Net income from continuing operations	26.5	21.1	17.8	21.1	19.5
Funds from operations (FFO)	85.2	72.5	51.4	48.4	49.7
Capital expenditures	79.2	66.0	46.2	61.7	58.3
Dividends paid	10.5	31.1	8.5	4.7	6.6
Debt	442.6	406.7	319.2	261.8	255.1
Equity	282.3	265.3	215.6	207.5	190.3

Table 4

PowerStream Inc.--Financial Summary (cont.)

Debt and equity	724.9	672.0	534.8	469.3	445.4
Adjusted ratios					
EBITDA interest coverage (x)	4.2	3.9	3.5	4.0	4.4
FFO interest coverage (x)	4.3	3.9	2.7	2.7	3.6
FFO/debt (%)	19.2	17.8	16.1	18.5	19.5
Discretionary cash flow/debt (%)	(1.7)	(12.3)	(5.7)	(2.4)	(13.9)
Net Cash Flow / Capex (%)	94.2	62.7	92.9	70.7	73.9
Debt/debt and equity (%)	61.1	60.5	59.7	55.8	57.3
Return on common equity (%)	9.0	8.1	8.0	9.8	10.2
Common dividend payout ratio (unadjusted; %)	39.8	147.6	47.8	22.4	33.6

NR--Not rated.

Table 5

Reconciliation Of PowerStream Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2010--									
PowerStream Inc. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	415.0	286.6	856.4	105.3	59.1	22.4	84.4	84.4	10.5	67.1
Standard & Poor's adjustments										
Operating leases	13.6	N/A	N/A	0.5	0.5	0.5	0.2	0.2	N/A	13.7
Postretirement benefit obligations	14.0	(4.3)	N/A	1.4	1.4	1.0	(0.6)	(0.6)	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	1.5	(1.5)	(1.5)	N/A	(1.5)
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	0.4	N/A	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.7	N/A	N/A
Total adjustments	27.6	(4.3)	0.0	1.8	2.2	2.9	(2.0)	0.7	0.0	12.2
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	442.6	282.3	856.4	107.1	61.3	25.3	82.4	85.2	10.5	79.2

N/A--Not applicable.

Related Criteria And Research

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings Detail (As Of March 1, 2012)	
Electricity Distributors Finance Corp.	
Senior Unsecured (1 Issue)	A
Business Risk Profile	Excellent
Financial Risk Profile	Significant

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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The McGraw·Hill Companies

Rating Report

Report Date:
January 31, 2012

Previous Report:
March 18, 2011

Insight beyond the rating.

Electricity Distributors Finance Corporation

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The Company

Electricity Distributors Finance Corporation (EDFIN) was incorporated for the purpose of providing Ontario electric distributors with efficient access to the debt capital markets. EDFIN purchases debentures and other evidences of indebtedness issued by local distribution companies and sells to investors, by way of private placement, certificates evidencing undivided co-ownership interests in such debentures or evidences of indebtedness. EDFIN has no assets or liabilities. EDFIN is administered by the MEARIE Group, a Canadian insurance supplier dedicated to the electricity sector.

The two participating LDCs in EDFIN are PowerStream Inc. and Enwin Utilities Ltd.

Rating

Debt	Issuing Entity	Rating	Rating Action	Trend
Series 2002-1 Certificates	Electricity Distributors Finance Corporation	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating on the Series 2002-1 Certificates (the Certificates) issued by Electricity Distributors Finance Corporation (EDFIN) at A (low) with a Stable trend. The rating is based on the lower rating of two participants, Enwin Utilities Ltd. (Enwin), rated A (low), and PowerStream Inc. (PowerStream), rated "A" (refer to attached credit reports on Enwin and PowerStream).

The Certificates represent undivided co-ownership interests in unsecured debentures issued by two participating local distribution companies (LDC Participants), namely PowerStream and Enwin, to EDFIN. The obligations of the individual LDC Participants are several and not joint, and each LDC Participant is liable only for its obligations and not for the obligations of any others. Default of the obligations to EDFIN of one LDC Participant will result in a proportionate default of the unsecured debentures issued by EDFIN. Therefore, the rating of the Certificates is based on the rating of the lowest-rated LDC Participant, Enwin.

The debt issued through the Certificates was loaned to the LDC Participants through debentures ("Debentures"; with the same maturity date as the Certificates) issued to EDFIN by the LDC Participants. EDFIN then used the cash receipts to pay the interest on the Certificates. The stability of cash flows at the LDC Participants, combined with adequate liquidity, has continued to allow the LDC Participants to make timely and sufficient payments to EDFIN.

EDFIN's rating is expected to be discontinued when the Certificates mature on August 15, 2012, as the LDC Participants are expected to retire their Debentures issued to EDFIN with their own debt issuances. The refinancing risk (paying back the loans to EDFIN) of Enwin and PowerStream is expected to be modest, given the good liquidity and financial strength of these utilities.

Rating Considerations

Strengths	**Challenges**
(1) Low business risk, stable regulatory framework	(1) Refinancing risk
(2) Solid balance sheets and strong credit metrics	(2) Relatively low regulatory returns
(3) LDC Participants' obligations	(3) Earnings are exposed to the volume risk

Financial Information

For 12 months ended Sept. 30, 2010 (Unaudited)	Underlying Utility Debentures ($ millions)	Rate Base ($ millions)	Total Debt-to-Capital	EBIT Interest Coverage (times)	Cash Flow-to-Debt	DBRS Issuer Rating
PowerStream Inc.	125	677	58.1%	2.28	20.6%	A
Enwin Utilities Ltd.	50	205	47.7%	3.90	34.1%	A (low)

Structure

Issuer:	Electricity Distributors Finance Corporation
Amount:	$175.0 million
Term:	10 years through August 15, 2012
Interest Rate:	6.45%; payable semi-annually
Amortization:	Bullet maturity
Security:	None
Deposited Securities:	Each debenture is a direct obligation of the LDC Participant that issued the debenture. The LDC Participants' obligations are several and not joint, and each LDC is liable only for its obligations and not for the obligations of any other LDC Participants.
Ranking:	All ownership interests rank equally with respect to their rights pursuant to each underlying debenture. Each underlying debenture is a direct, unsecured obligation of the LDC that issued it, ranking pari passu with all other debentures and prescribed debt instruments of such LDC. However, the unsecured debentures rank senior to all debt in the form of promissory notes held by the municipal shareholders of each LDC Participant.
Redemption:	Each participating LDC has the right to redeem, in part or in whole, the debenture issued by it, at any time prior to the maturity date, at a price equal to the greater of: (1) par, and (2) the Canada Yield Price plus accrued and unpaid interest.
Key Covenants:	Each LDC will: (1) ensure that its funded obligations do not exceed 75% of its consolidated net worth; (2) not pledge its primary assets; (3) not enter into any sale and leaseback transaction exceeding 10% of its consolidated net worth; (4) not invest in energy retailing beyond 20% of its consolidated net worth.

Rating

Debt	Issuing Entity	Rating	Rating Action	Trend
Series 2002-1 Certificates	Electricity Distributors Finance Corporation	A (low)	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008	2007
Series 2002-1 Certificates	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)

Electricity Distributors Finance Corporation

Report Date:
January 31, 2012

The Company

Enwin Utilities Ltd. is an LDC that serves over 85,400 customers in the Windsor service area. Enwin Utilities Ltd. is wholly owned by Windsor Canada Utilities Ltd., which in turn is wholly owned by the City of Windsor.

Enwin Utilities Ltd.

Rating

Debt	Issuing Entity	Rating	Rating Action	Trend
Issuer Rating	Enwin Utilities Ltd.	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the Issuer Rating of Enwin Utilities Ltd. (Enwin, formerly Enwin Powerlines Ltd., or the Company) at A (low) with a Stable trend. The confirmation reflects Enwin's strong financial profile and stable and low business risk profile, stemming from its stable regulated electricity distribution operations and a good record of operational efficiency.

Enwin's rating has been supported by its strong financial profile, reflecting a low-leverage balance sheet and very strong interest coverage and cash flow ratios for the current rating category. All credit metrics have been relatively stable over the past few years. DBRS notes that the Company's capex for 2011 was lower than its peak levels in 2009 and 2010, which were largely driven by higher spending to improve reliability and fund the installation of smart meters. As a result, the Company generated a cash flow surplus (after working capital), which was used to modestly reduce debt in 2011. The Company has continued to maintain its leverage ratio in the mid-40% range, which is relatively low compared with other utilities. This low leverage provides significant financial flexibility.

Enwin's low business risk profile is underpinned by a stable regulatory framework. The Company currently operates under the Incentive Regulation Mechanism (IRM) and is expected to have its rebasing year in the 2013-2014 year. DBRS views IRM as reasonable, as it allows utilities to pass on purchased power costs and recover prudent capex incurred during the IRM period in the rebasing year. With a recent change in the Ontario Energy Board's (OEB) return-on-equity (ROE) calculation, a higher ROE in the mid-9.00% range is expected for Enwin in the next rebasing year.

Despite these strengths, Enwin has significant exposure to large industrial customers, particularly in the auto sector. In addition, Enwin operates in a relatively weak franchise area with minimal load growth. DBRS notes that the impact of the 2008 economic downturn and the restructuring of the auto sector was manageable. Enwin has experienced minimal payment defaults over the past several years, while its distribution rates have continued to increase moderately.

DBRS expects that Enwin will continue to maintain its conservative leverage strategy to support its current rating. DBRS notes that Enwin has $50 million in debt (approximately two-thirds of its total debt) owed to EDFIN, maturing in August 2012, which they are currently in the process of refinancing. DBRS does not expect any major refinancing issues for Enwin, given its stable regulated business profile and strong financial profile.

Rating Considerations

Strengths	Challenges
(1) Strong financial profile	(1) Average franchise area with low growth
(2) Stable regulatory system	(2) Large exposure to industrial customers
(3) Cost containment	(3) Relatively small size

Financial Information

ENWIN Utilities Ltd.	12 months ended	For the year ended December 31			
	Sep. 30, 2011	2010	2009	2008	2007
EBIT interest coverage (times)	3.90	4.71	4.75	3.53	3.09
Total debt-to-capital	45.7%	47.7%	46.2%	43.0%	47.5%
Cash flow-to-total debt	34.1%	35.4%	25.9%	30.5%	26.9%
Debt/EBITDA	2.39	2.39	2.16	2.52	2.87
Total debt ($ millions)	75.23	77.43	65.11	67.74	77.24
Cash flow from operations ($ millions)	25.67	27.38	16.89	19.69	19.96
Net income before extras. ($ millions)	10.98	12.51	8.75	7.39	15.44
Return on average equity	12.8%	15.6%	10.9%	8.8%	18.6%

Rating Considerations Details

Strengths

(1) Enwin's financial profile has been very strong for the current rating, with below-average debt leverage and superior interest coverage and cash flow ratios when compared to its utility peers. Strong credit ratios are key for Enwin to maintain its A (low) rating, given its relatively small size.

(2) Enwin's business risk profile is supported by a stable and reasonable regulatory system under IRM, which allows the Company to fully recover its purchased power costs in a timely fashion. IRM also allows the Company to recover its capex incurred during the IRM period in the rebasing year, which is expected to be the 2013-2014 year.

(3) Enwin's cost containment has been impressive despite its relatively small-size operations. Operational efficiency is key to achieving higher earnings under IRM.

Challenges

(1) Enwin's franchise area has experienced almost no customer growth over the past few years. A low-growth rate franchise will likely limit earnings growth going forward.

(2) Enwin is exposed to economically sensitive industrial customers. Despite the auto sector recovering from a restructuring period in 2008 and 2009, the industry is still exposed to economic conditions which can have a large impact on electricity throughput volumes and, therefore, earnings and cash flow to Enwin.

(3) The Company has approximately 85,425 customers, which is relatively small compared to other electricity distributors covered by DBRS (e.g., Toronto Hydro Corporation, Hydro Ottawa Holdings Inc. and PowerStream). Small size limits the Company's ability to raise funds to finance its major capex, if required.

Regulation

- Enwin is regulated by the OEB under the Ontario Electricity Act, 1998. The Company's regulatory rate year runs from May 1 to April 30.
- Enwin operates under IRM, under which the Company is subject to a formula price cap that allows for an annual increase in distribution rates based on inflation, less a productivity factor, which can be reset annually.
- Under IRM, if Enwin's actual rate of ROE is 300 basis points (bps) above or below the allowed ROE, the OEB will undertake a review. If earnings are more than 300 bps over ROE, they may be re-distributed to customers.
- In addition to IRM, the Company is allowed to file a cost-of-service (COS) application, which is expected every four to five years.
- In the rebasing year the Company could be allowed, subject to the OEB's approval, to add prudently incurred capital expenditures spent during the IRM period to its rate base.
- In 2012, ROE is expected to be in line with 2011, which was reasonable at 9.96%.
- Enwin is allowed to fully recover its purchased power costs (except doubtful accounts on power cost, which are manageable) in a timely fashion, eliminating its exposure to power price risk. DBRS views this as a positive factor in the current regulatory system in Ontario (regardless of whether the Company operates under IRM or COS).
- The Company delayed a COS application and will file an IRM application for 2013.

Earnings and Outlook

Enwin - Earnings Highlights	12 months ended	For the year ended December 31			
($ millions)	Sep. 30, 2011	2010	2009	2008	2007
EBITDA	31.5	32.4	30.1	26.9	26.9
EBIT	16.7	18.7	18.7	15.7	16.0
Interest expense	4.3	4.0	3.9	4.5	5.2
Income taxes or in lieu of taxes	1.5	2.2	6.0	3.9	(4.7)
Net income bef. Extra. Items	11.0	12.5	8.8	7.4	15.4
Net income	10.6	11.3	10.2	7.6	15.7
EBIT margins	25.5%	28.3%	30.6%	26.5%	27.8%

Summary

- Overall, Enwin's earnings have been relatively stable in 2011, reflecting its regulated distribution business, which accounts for most of its earnings.
- The Company is exposed to the decline of its large users (in the auto sector) in the Windsor area, which was impacted by the weakening of the auto sector in 2008 but has stabilized since 2009.
- Earnings stability has been mainly supported by stable residential (25% of total throughput) and General Services (45%).
- 2011 earnings also benefited from an ROE of 9.96%, which was higher than previous years.
- Customer growth in Enwin's service area has been flat over the past five years.

Outlook

- The Company's 2012 earnings are expected to remain stable with a very modest increase expected in the second half when the new rates for the next regulatory period become effective.
- The expected increase will be dependent on the outcome of the Company's May 2012 to April 2013 rate application (under IRM), which requests a rate increase associated with the impact of loss revenues due to various conservation initiatives and for the disposition of a deferred account.
- ROE in 2012 is expected to be in line with 2011; the rate base ($206.1 million) is expected to remain largely unchanged until the next rebasing year.

Financial Profile and Outlook

Enwin - Cash Flow Highlights	12 months ended	For the year ended December 31			
($ millions)	Sep. 30, 2011	2010	2009	2008	2007
Cash flow form operations	25.7	27.4	16.9	19.7	20.0
Dividends	(3.0)	(4.0)	(3.3)	(5.0)	(3.0)
Capex	(8.4)	(17.2)	(17.3)	(10.0)	(10.3)
Free cash flow before working capital	14.2	6.2	(3.6)	4.7	6.7
Changes in working capital	9.1	(8.4)	9.3	0.2	3.0
Net free cash flow	23.4	(2.2)	5.7	4.9	9.7
Net investment activities	0.2	0.1	0.2	0.2	1.4
All other non-cash/adjustments	(14.8)	(9.2)	11.5	4.7	4.5
Changes in debt	(5.1)	8.2	(11.8)	(9.0)	(18.6)
Due to (from) related parties	(3.6)	(3.6)	17.1	(0.7)	3.0
Net change in cash	(0.0)	(6.7)	22.7	0.0	0.0
Key Credit Ratios					
Debt/capital	45.7%	47.7%	46.2%	43.0%	47.5%
Debt/capital (external debt only)	37.9%	40.6%	39.8%	40.6%	44.9%
EBITDA interest coverage	7.34	8.18	7.65	6.03	5.21
EBIT interest coverage	3.90	4.71	4.75	3.53	3.09
Cash flow-to-debt	34.1%	35.4%	25.9%	30.5%	26.9%
Debt/EBITDA	2.39	2.39	2.16	2.52	2.87
Return on Equity	12.8%	15.6%	10.9%	8.8%	18.6%
Dividend payout	27.3%	32.0%	37.1%	67.7%	19.4%

Summary

- Enwin's financial profile remained strong for the current rating, with modestly low debt levels (all of its long-term debt is from Debentures issued to EDFIN) and very strong interest coverage and cash flow ratios.
- Positive free cash flow (before changes in working capital) was generated in 2010 and 2011 despite historical high capex in 2010 to improve system reliability and install smart meters.
- Dividend payouts (average at 39% over the past four years) have been among the lowest compared to other utilities.
- Large swings in working capital over the past three years were mainly due to timing differences in the Company's cost-deferred accounts.
- Enwin maintains one of the lowest balance sheet leverages among its peers. This is necessary to support the current rating, given its small size and average franchise area.

Outlook

- Capex is expected to remain modest, following peak capex levels in 2009 and 2010, and as a result, DBRS expects the Company to continue to generate positive free cash flows in 2012.
- DBRS expects Enwin to continue to maintain its balance sheet leverage in line with historical levels.

Long-Term Debt and Bank Lines

Liquidity

- Enwin's liquidity remains sufficient to finance its ongoing working capital needs. The Company has an unsecured committed $75 million revolving term facility which will mature in February 2012.
- As of September 30, 2011, the amount available was $70 million.
- Enwin has a letter of credit with the Independent Electricity System Operator (IESO), and as of September 30, 2010, no amount was outstanding.

Long-Term Debt Maturity

- Enwin has $50 million in debentures issued to EDFIN, maturing on August 15, 2012.
- DBRS believes that refinancing the EDFIN debt is within the Company's capacity.

ENWIN Utilities Ltd.

Balance Sheet ($ millions)	Sept 30,	As at December 30				Sept 30,	As at December 31	
Assets	2011	2010	2009	**Liabilities & Equity**		2011	2010	2009
Cash & short-term investments	-	-	6.7	Short-term debt		25.4	27.7	15.1
A/R + unbilled revenue	38.2	31.1	29.9	A/P + accruals		22.8	26.7	28.9
Inventories	3.0	4.0	2.2	Other Current Liab.		2	1	9
Regulatory assets	-	-	-	**Current Liabilities**		50.1	55.5	53.4
Other	3.3	5.4	0.8	Customer deposits		5.8	7.0	7.4
Current Assets	44.5	40.5	39.6	Long-term debt		49.8	49.7	50.0
Net fixed assets	180.3	183.0	179.9	Other liabilities		49.0	45.7	53.0
Net investment in lease	0.0	-	0.0	Shareholders' equity		89.5	84.8	75.8
Other assets	19.5	19.1	20.1					
Total	244.3	242.6	239.6	**Total**		244.3	242.6	239.6

ENWIN Utilities Ltd.	12 months ended	For the year ended December 30							
Ratios/Operating Stats	Sept 30, 2011	2010	2009	2008	2007	2006	2005	2004	2003
Operating margin	25.5%	28.3%	30.6%	26.5%	27.8%	20.3%	21.2%	18.0%	23.0%
Pre-tax margin (bef. extras.)	19.0%	22.3%	24.1%	19.0%	18.8%	10.4%	7.2%	3.9%	7.8%
Return on avg. common equity	12.8%	15.6%	10.9%	8.8%	18.6%	14.3%	4.2%	2.1%	4.4%
Rate base ($ millions)	206.1	205.0	205.0	186.5	186.5	186.5	165.4	161.3	161.3
Peak system demand (MW)		518	495	532	669	669	669	602	609
Electricity Throughputs									
Residential		647.5	608.1	637.1	665.0	655.1	708.5	646.6	684.0
General service		1,168.0	1,187.7	1,295.0	1,352.1	1,285.7	1,353.2	245.8	1,471.0
Large users		446.3	650.3	781.4	945.1	1,006.7	1,059.0	1,076.4	1,057.0
Street lighting/Other		70.7	16.9	17.0	16.9	16.9	16.7	16.5	23.0
Total – (GWh)		2,332.5	2,463.0	2,730.5	2,979.1	2,964.4	3,137.4	1,985.3	3,235.0
Growth in electricity throughputs									
Number of Customers									
Residential		76,720	76,528	76,400	76,496	76,407	75,921	75,107	73,512
General service		8,133	8,159	8,234	8,251	8,283	8,324	8,699	8,638
Large users		10	10	10	10	11	9	9	10
Street lighting/Other		165	2	2	2	2	2	1	1
Total		85,028	84,699	84,646	84,759	84,703	84,256	83,816	82,161
Unit Revenues & Costs (cents per kWh throughputs)									
Average gross revenues		11.71	9.67	8.76	8.12	8.13	8.17	11.17	6.92
Power costs		8.89	7.19	6.58	6.19	6.20	6.91	9.19	5.68
Average net revenues		2.82	2.48	2.18	1.93	1.93	1.26	1.98	1.25
Variable costs (OM&A + PILS)		1.53	1.50	1.33	0.87	0.98	0.71	1.19	0.71
Fixed costs (deprec., int., gov't levies)		0.76	0.62	0.57	0.54	0.61	0.47	0.73	0.45
Total costs (excl. power costs)		2.29	2.13	1.90	1.41	1.59	1.18	1.92	1.16
Net margin		0.54	0.36	0.27	0.52	0.34	0.08	0.06	0.08

(1) Excludes municipal and property taxes.

Rating

Debt	**Issuing Entity**	**Rating**	**Rating Action**	**Trend**
Issuer Rating	Enwin Utilities Ltd.	A (low)	Confirmed	Stable

Rating History

	Current	**2011**	**2010**	**2009**	**2008**	**2007**
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)

Electricity Distributors Finance Corporation

Report Date:
January 31, 2012

The Company

PowerStream Inc. was created in 2004 through the merger of three local distribution companies – Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc. and Richmond Hill Hydro Inc. PowerStream acquired Aurora Hydro Connections Ltd. on November 1, 2005. Following the January 1, 2009, merger with Barrie Hydro Distribution Inc., PowerStream is currently 45% owned by the City of Vaughan, 34% by the Town of Markham and 21% by the City of Barrie. It is the second largest municipally owned electricity distribution company in Ontario, providing service to residential and business customers in the municipalities of Aurora, Markham, Richmond Hill, Barrie, Vaughan and 11 Simcoe counties. The Company serves approximately 336,000 customers in a service area of 806 square kilometres.

PowerStream Inc.

Rating

Debt	**Issuing Entity**	**Rating**	**Rating Action**	**Trend**
Issuer Rating	PowerStream Inc.	A	Confirmed	Stable

Rating Rationale

DBRS has confirmed the Issuer Rating of PowerStream Inc. (PowerStream or the Company) at “A” with a Stable trend. The rating reflects the Company’s low-risk, regulated electricity distribution operations, its solid financial profile and a strong franchise area with a favourable customer mix.

The business risk profile has improved following the merger with Barrie Hydro Distribution Inc. (Barrie Hydro) in 2009, providing a much larger customer base, greater diversification and strong population growth in the Barrie area. The Company currently operates under the IRM, which is viewed by DBRS as reasonable and stable, allowing PowerStream to recover purchased power costs on a timely basis. A cost-of-service application is expected to be filed in the rebasing year, generally every four or five years (the next rebasing year is expected to be 2013). Returns on equity investment and the size of the rate base are expected to increase in the rebasing year. DBRS views the new rate rider, effective January 2011, allowing for the recovering of costs associated with smart meters in 2008 and 2009, as a positive factor to the Company’s cash flow.

The Company’s financial profile has remained stable, underpinned by improved earnings and cash flow, as a result of customer growth and operational efficiency achieved under IRM. However, debt levels were higher in 2010 and 2011 than in previous years, as new debt was issued to finance free cash flow deficits resulting from higher capital spending (capex) to maintain system capacity and reliability. Despite higher debt levels, the Company’s credit metrics have remained well within the current “A” rating category.

DBRS notes that the Company is committed to maintaining its debt-to-capital ratio in line with the regulatory 60% debt to 40% equity structure. This level is reasonable for the current rating. However, the debt leverage ratio is viewed as strong when debt owed to the parents (interest could be deferred) was excluded, providing significant flexibility for the Company going forward, especially when the Debentures owed to EDFIN mature in August 2012.

Rating Considerations

Strengths	**Challenges**
(1) Strong franchise area with good growth	(1) Managing capital expenditures
(2) Second largest LDC in Ontario	(2) Low regulated returns
(3) Solid financial metrics	(3) Performance pressure under IRM

Financial Information

PowerStream Inc.	12 months ended	As at December 31			
	Sept 30, 2011	2010	2009 (2)	2008	2007
EBIT interest coverage (times)	2.28	2.60	2.28	2.58	3.48
Total debt-to-capital (1)	58.1%	59.1%	59.6%	58.7%	54.8%
Cash flow-to-total debt (1)	20.6%	21.1%	18.7%	18.7%	22.6%
Debt to EBITDA	3.92	3.89	4.23	4.27	3.20
Operating cash flow ($ millions)	85.4	87.1	73.9	57.8	57.2
Net income ($ millions)	24.4	27.0	20.8	17.8	21.1
Cash flow-to-capex	1.77	1.24	1.00	1.23	0.94
Return on average equity	8.3%	8.3%	8.6%	8.3%	20.2%

(1) Includes subordinate debt (promissory notes to shareholders).

(2) 2009 financials include the combined results of Barrie Hydro Holdings Inc. and Powerstream

Rating Considerations Details

Strengths

(1) PowerStream's franchise area is one of the strongest in Ontario, with relatively strong customer growth, averaging 2% over the past few years. The customer mix is also favourable, with residential customers accounting for nearly 90% of total customers in 2010. This reduces the Company's exposure to economic conditions as residential demand is very consistent.

(2) With approximately 336,000 customers, the Company is the second largest electricity utility in Ontario (behind Toronto Hydro Corporation). The size of the customer base allows the company to operate more efficiently as they can take advantage of economies of scale, especially under IRM.

(3) PowerStream has continued to maintain a solid balance sheet and strong credit metrics for its current rating category, with a debt-to-capital ratio of 58%, EBIT-interest coverage of 2.28 times and a cash flow-to-debt ratio of 20.6% (for the 12 months ended September 30, 2011).

Challenges

(1) The Company has a large capex program to maintain its reliability system and expand its distribution networks. Large capex could result in negative free cash flow, which would require external financing. In addition, extra capex beyond the amount approved by the OEB may not be added to the rate base until the rebasing year.

(2) The approved ROE of 8.01% in 2011 was established by the OEB in 2008 for 2009 rate filers. This level was low and was primarily due to the low interest rate environment. While the OEB has changed its methodology for calculating ROE, and updates this parameter annually, the resulting increase in the ROE can only be realized by the company after they rebase.

(3) Under IRM, PowerStream's annual rate increases are limited by a regulatory formula that includes inflation and the Company's productivity factor. The Company must achieve productivity at least equal to the regulatory productivity factor in order to achieve the allowed ROE.

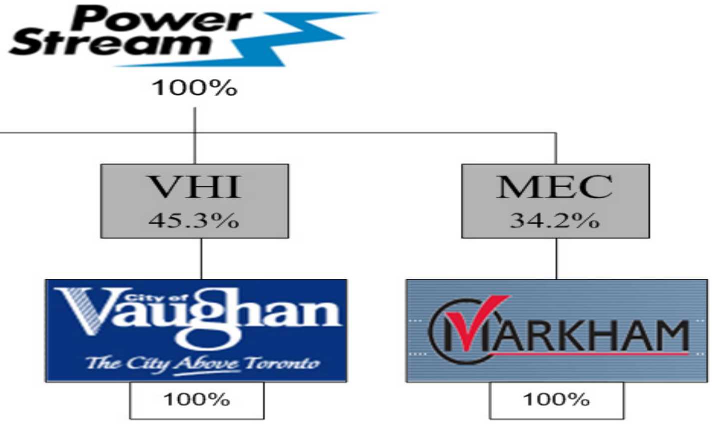
Regulation

- PowerStream is regulated by the OEB under the Ontario Electricity Act, 1998. The Company's regulatory rate year runs from May 1 to April 30.
- PowerStream operates under IRM, under which the Company is subject to a formula price cap that allows for an annual increase in distribution rates based on inflation less a productivity factor, which can be reset annually.
- Under IRM, if the Company's actual ROE is 300 basis points (bps) above or below the allowed ROE, the OEB will undertake a review, and earnings over 300 bps may be shared with customers.
- In addition to IRM, the Company is allowed to file a cost-of-service (COS) application, which is expected every four to five years. The next rebasing year is 2013 for PowerStream.
- The Company is expected to file a COS application in 2012 for new rates effective January 2013.
- In the rebasing year, the Company could be allowed, subject to the OEB's approval, to add prudently incurred capital expenditure already spent during the IRM period to its rate base.
- In 2012, allowed ROE remains at 8.01% and deemed equity is 40%, both of which are reasonable levels. The Company's ROE is expected to increase to the mid-9.00% range in accordance with the OEB's 2009 report.
- PowerStream is allowed to fully recover its purchased power costs (except doubtful accounts on power cost, which are manageable) in a timely fashion, eliminating its exposure to power price risk. DBRS views this as a positive factor in the current regulatory system in Ontario (regardless of whether the Company operates under IRM or COS).

Electricity Distributors Finance Corporation

Report Date:
January 31, 2012

Ownership Structure



Earnings and Outlook

PowerStream - Earnings Highlights	12 months ended	As at December 31			
($ millions)	Sept 30, 2011	2010	2009 (1)	2008	2007
EBITDA	105.8	106.3	93.4	72.6	79.1
EBIT	59.2	60.0	51.3	41.2	49.4
Gross interest expense	25.9	23.1	22.5	16.0	14.2
Net income bef. extraordinary items	24.4	27.0	20.8	17.8	21.1
Net income	24.1	26.5	21.1	17.8	21.1

(1) 2009 results include the results of Barrie Hydro Holdings Inc.

Summary

- Overall, PowerStream's earnings have increased since the amalgamation with Barrie Hydro in 2009. Most of PowerStream's earnings are generated from electricity distribution operations.
- The increase in 2010 compared to 2009 was largely due to cost containment under IRM. The amalgamation allowed PowerStream to achieve some synergies.
- Earnings stability is supported by a sizable customer base, with approximately 336,000 customers. Approximately 90% of the customers are residential, mitigating PowerStream's exposure to economic conditions.
- Earnings in 2011 continued to remain stable. A slight decrease to net earnings in the last 12 months (LTM) 2011 (compared to 2010) was due to higher depreciation, which did not affect cash flow.

Outlook

- Barring an extreme change in weather pattern, outlook for 2012 earnings is expected to remain comparable to 2011, until 2013 (the rebasing year) when PowerStream's rate base and ROE are expected to increase.

Electricity Distributors Finance Corporation

Report Date:
January 31, 2012

Financial Profile and Outlook

PowerStream - Cash Flow Highlights	12 months ended	As at December 31			
($ millions)	Sept 30, 2011	2010	2009(*)	2008	2007
Net income (before extras)	24.4	27.0	20.8	17.8	21.1
Depreciation	49.9	49.8	45.4	32.9	31.5
Other non-cash items	11.1	10.4	7.7	7.1	4.6
Cash Flow From Operations	85.4	87.1	73.9	57.8	57.2
Common dividends	(13.9)	(10.5)	(31.1)	(8.5)	(4.7)
Capital expenditures	(48.4)	(70.0)	(73.7)	(47.0)	(60.8)
Cash Flow Before Working Capital	23.2	6.6	(30.9)	2.4	(8.3)
Changes in working capital	(6.3)	(2.7)	(23.3)	(14.9)	11.8
Free Cash Flow	16.9	3.9	(54.2)	(12.5)	3.5
Merger/Acquisition/Other investment	(0.3)	0.1	0.2	0.1	9.9
Change in regulatory assets	(9.2)	(28.4)	(23.3)	1.7	(3.5)
Net change in equity	4.3	2.4	-	-	-
Net change in debt	(0.5)	(0.3)	15.0	50.0	-
Other financing	(25.6)	(11.8)	21.2	(6.1)	10.3
Net Change in Cash	(14.4)	(34.0)	(41.1)	33.1	20.2
Key Financial Ratios					
Total debt-to-capital (1)	58.1%	59.1%	59.6%	58.7%	54.8%
Total debt-to-capital (2)	47.6%	50.3%	50.4%	49.3%	42.8%
EBITDA interest coverage	4.08	4.60	4.15	4.55	5.57
EBIT interest coverage	2.28	2.60	2.28	2.58	3.48
Cash flow-to-total debt	20.6%	21.1%	18.7%	18.7%	22.6%
Return on Equity	8.3%	8.3%	8.6%	8.3%	20.2%
Dividend payout	56.8%	39.0%	149.1%	47.8%	22.2%

(1) Include subordinate debt owed to shareholders; (2) Exclude subordinate debt owed to shareholders

(*) 2009 results include the results of Barrie Hydro Holdings Inc.

Summary

- PowerStream generated positive free cash flow in 2010 and 2011, reflecting stronger cash flows, lower dividends and a modest decline in capex.
- Despite a decline, capex remained large in 2010 and 2011, mainly due to higher capital spending on transformer stations, transformers and smart meters.
- The Company maintained a minimum dividend payout ratio of 50% of net income. Payout depends on the Company’s cash position, working capital requirements and net capital expenditures.
- Following a significant increase in 2009 (due to the acquisition of Barrie Hydro), debt levels remained relatively stable in 2010 and 2011.
- The Company’s debt leverage (including debt owed to its parents) remained reasonable at or below the 60% regulatory debt ratio (in line with the regulatory capital structure). Excluding debt owed to its parents, the debt leverage was low in the 48% to 50% range.
- Cash flow-to-debt and interest coverage ratios have trended lower in recent years as a result of increased debt levels; however, these metrics continue to remain solid and are in line with the “A” rating range.

Outlook

- Cash flow in 2012 is expected to remain stable as the Company continues to operate under IRM with almost no changes in its 2011 ROE and the rate base.
- The Company’s rate base is expected to increase in the rebasing year (2013); this should improve cash flow over the next IRM period.
- DBRS expects the Company to continue to maintain its balance sheet leverage at 60%, in line with the OEB-approved deemed capital structure. Interest coverage and cash flow metrics are expected to remain relatively stable, similar to the 2011 level, and continue to be supportive of the “A” rating.

Long-Term Debt and Bank Lines

Summary

Liquidity

- PowerStream’s liquidity remained sufficient to finance its ongoing working capital and capex requirements.
- At the end of 2011, the Company had a $75 million committed revolving facility. The available amount was $60 million.
- The Company is currently in the process of finalizing a $125 million committed backstop facility with a commercial bank. This facility is expected to be used if PowerStream is unable to refinance the EDFIN Certificates at maturity.

Long-Term Debt

PowerStream’s long-term debt currently consists of the following:

- Senior unsecured debentures totalling $125 million issued to EDFIN, maturing on August 15, 2012.
- Subordinate debt to shareholders (promissory notes) totalling $166.1 million.
  - $78.2 million, 5.58%, due 2024, held by the City of Vaughan.
  - $67.9 million, 5.58%, due 2024, held by the Town of Markham.
  - $20.0 million, 5.58%, due 2024, held by the City of Barrie.
- The three promissory notes are repayable 90 days following demand from its owners. These notes have been classified as long term by PowerStream as it is not the intent of any of its owners to demand repayment within the next year.
  - The interest on the City of Vaughan and Town of Markham’s promissory notes was deferred for eight quarters commencing October 1, 2006, and for a five-year period from October 2008 and will be repayable in full on October 31, 2013. This amounts to approximately $16.3 million in deferred interest expense.

Electricity Distributors Finance Corporation

Report Date:
January 31, 2012

PowerStream Inc.

Balance Sheet
($ millions)

	Sept 30	As at December 31			Sept 30	As at December 31	
Assets	2011	2010	2009	**Liabilities & Equity**	2011	2010	2009
Cash & short-term investments	(11.9)	8.6	42.6	Short-term debt	40.0	40.0	40.0
A/R & unbilled revenue	184.4	161.6	161.8	A/P & accruals	103.9	117.8	123.5
Inventories	2.7	3.1	3.9	Other	14.3	13.1	8.4
Other	1.7	2.7	4.1	**Current Liabilities**	158.1	170.9	171.9
Current Assets	176.8	175.9	212.4	Customer deposits	12.3	12.1	16.7
Net fixed assets	649.8	642.1	601.8	Long-term debt	374.4	373.9	355.5
Regulatory assets	31.8	32.0	26.4	Regulatory liabilities	65.7	68.3	91.1
Other assets	58.2	58.1	65.9	Other liabilities	49.2	38.8	45.5
Goodwill & other assets	42.5	42.5	42.5	Shareholders' equity	299.4	286.6	268.2
Total	959.1	950.6	949.0	**Total**	959.1	950.6	949.0

	12 months Sept 30	As at December 30				
Ratios/Operating Stats	2011	2010	2009 (1)	2008 (2)	2008	2007
Operating margin	35.0%	35.8%	32.9%	34.1%	34.0%	39.5%
Pre-tax margin	20.9%	22.8%	18.9%	21.7%	20.8%	28.2%
Return on avg. common equity	8.3%	9.7%	8.6%	10.3%	8.3%	20.2%
Rate base ($ millions)(*)	711	677	626	649	499	463
Peak system demand (MW)(*)	1,961	1,896	1,756	1,756	1,444	1,519
Total throughput (GWh)(*)	8,658	8,611	8,026	8,438	6,829	6,873
Number of Customers						
Residential (*)	297,962	290,951	283,665	277,836	215,323	207,783
General service (*)	37,809	37,456	37,031	36,364	29,249	28,434
Large users (*)	1	1	1	1	1	3
Street lighting (*)	163	178	172	22	15	48
Total	335,935	328,586	320,869	314,223	244,588	236,268
Unit Revenues & Costs						
Average gross revenues	10.50	9.95	9.69	8.92	8.88	8.95
Power costs	8.53	8.03	7.75	7.08	7.10	7.13
Average net revenues	1.97	1.92	1.94	1.84	1.77	1.82
Variable costs	0.87	0.82	0.89	0.86	0.82	0.87
Fixed costs (deprec., int., gov't levies)	0.81	0.80	0.80	0.71	0.69	0.64
Total costs (excl. power costs)	1.68	1.61	1.68	1.57	1.51	1.51
Net margin	0.29	0.30	0.26	0.27	0.26	0.31

(1) 2009 results include the results of Barrie Hydro Holdings Inc.

(2) 2008 results are the DBRS estimate of the combined full year results of both Barrie Hydro and PowerStream

(*) 2011 was based on December 31.

Rating

Debt	**Issuing Entity**	**Rating**	**Rating Action**	**Trend**
Issuer Rating	PowerStream Inc.	A	Confirmed	Stable

Rating History

	Current	**2011**	**2010**	**2009**	**2008**	**2007**
Issuer Rating	A	A	A	A	A	A

Electricity Distributors Finance Corporation

Report Date:
January 31, 2012

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Schedule 21

OEB SCHEDULES – SUPPLEMENTARY TO EVIDENCE

FIXED ASSET CONTINUITY SCHEDULE (000's)
YEAR: 2009
CGAAP

APPENDIX 2-B

						COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**PS GL Account**	**GL account to map**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets														
47	1610	1610	Hydro One TS - Contributed Capital	4.00%		0	0	0	0	0	0	0	0	0
n/a	1805/1905	1805	Land	0		8,093	342	0	8,435	0	0	0	0	8,435
CEC	1806/1906	1806	Land Rights	0	1	657	148	0	730	178	1	0	179	551
47	1808	1808	Building & Fixtures	2.00%		43,527	440	0	43,967	14,319	853	0	15,171	28,795
47	1810	1810	Major spare parts (New 2008)	0		7,619	8,843	(7,619)	8,843	0	0	0	0	8,843
47	1815	1815	Transformer Stations	2.50%		95,767	0	0	95,767	26,586	2,393	0	28,979	66,788
47	1820	1820	Distribution Stations	3.33%		10,840	681	0	11,520	4,406	342	0	4,749	6,772
47	1830	1830	Poles, Towers & Fixtures	4.00%		114,186	10,564	0	124,750	41,207	4,290	0	45,497	79,253
47	1835	1835	O/H Cond & Devices	4.00%		155,040	2,124	0	157,164	75,433	5,754	0	81,186	75,979
47	1840	1840	U/G Conduit	4.00%		146,092	8,219	0	154,310	62,549	5,660	0	68,209	86,101
47	1845	1845	U/G Cond & Devices	4.00%		293,297	24,597	0	317,894	154,344	11,459	0	165,803	152,090
47	1849	1850	Line Transformers	4.00%		241,532	10,800	0	252,332	122,721	9,065	0	131,786	120,546
47	1855	1855	Services (OH and UG)	4.00%		48,874	2,668	0	51,542	21,897	1,733	0	23,630	27,912
47	1860	1860	Meters	4.00%		46,363	2,702	(9,297)	39,768	22,991	1,538	(4,715)	19,815	19,954
47	1862	1860	Smart Meters	6.67%		0	9,777	0	9,777	0	1,629	0	1,629	8,147
			Subtotal Distribution Assets			1,211,886	81,903	(16,916)	1,276,798	546,630	44,719	(4,715)	586,633	690,166
General Plant Assets														
13	1870	1870	Leased Property	2.50%		575	0	0	575	575	0	0	575	0
47	1908	1908	Building & Fixtures - Head office	2.00%		26,545	672	0	27,217	319	560	0	879	26,337
13	1910	1910	Leasehold Improvements	16.67%	2	2,171	0	0	2,171	1,354	310	0	1,664	507
8	1915	1915	Office Equipment	10.00%		6,650	283	0	6,933	3,222	230	0	3,452	3,481
10	1920	1920	Computer hardware	20.00%		15,108	1,835	0	16,943	10,657	1,834	0	12,490	4,453
12	1925	1925	Computer Software	33.33%		13,632	1,965	0	15,597	10,008	2,704	0	12,712	2,885
10	1930	1930	Transportation	16.67%	2	19,229	4,082	(1,733)	21,577	12,868	2,207	(1,714)	13,360	8,217
8	1935	1935	Stores Equipment	10.00%		652	0	0	652	581	11	0	592	60
8	1940/1945	1940	Tools, Shop & Garage	10.00%		5,535	411	0	5,946	3,719	347	0	4,066	1,880
8	1955	1955	Communication Equipment	14.29%	2	1,286	591	0	1,877	513	84	0	597	1,280
8	1960	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	1980	System Supervisory Equip	6.67%		17,794	548	0	18,342	9,445	913	0	10,358	7,984
47	1990	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
12	1961	1925	Process Re-engineering	33.33%		735	444	0	1,179	252	319	0	571	608
			Subtotal General Plant Assets			109,911	10,830	(1,733)	119,008	53,513	9,519	(1,714)	61,318	57,690
Other Capital														
47	2005	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	0	0	0	0	0	0	0	0
			Subtotal Other Capital Assets			0	0	0	0	0	0	0	0	0
			Total Assets Before Contributed Capital	n/a		1,321,797	92,734	(18,649)	1,395,807	600,142	54,238	(6,429)	647,951	747,856
47	1995	1995	Contributed Capital	varies		(228,877)	(31,587)	0	(260,464)	(42,279)	(9,819)	0	(52,097)	(208,367)
			NET DISTRIBUTION ASSETS			1,092,920	61,146	(18,649)	1,135,342	557,864	44,419	(6,429)	595,853	539,489

NOTES:

1) Depreciation was recorded on land rights in prior years including 2009. This was removed in 2010 as it was determined that no depreciation should be applied.

2) More then one asset type in the class with different useful lives. Depreciation rate shown is based on the average useful life

FIXED ASSET CONTINUITY SCHEDULE (000's)
YEAR: 2010
CGAAP

APPENDIX 2-B

						COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**PS GL Account**	**GL account to map**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments (3)**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals/ Adjustments (3)**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets														
47	1610	1610	Hydro One TS - Contributed Capital	4.00%		0	0	0	0	0	0	0	0	0
n/a	1805/1905	1805	Land	0		8,435	1,952	0	10,386	0	0	0	0	10,386
CEC	1806/1906	1806	Land Rights	0	1	730	1	0	731	179	0	(179)	0	731
47	1808	1808	Building & Fixtures	2.00%		43,967	389	(37,185)	7,171	15,171	136	(14,070)	1,238	5,933
47	1810	1810	Major spare parts (New 2008)	0		8,843	(438)	0	8,404	0	0	0	0	8,404
47	1815	1815	Transformer Stations	2.50%		95,767	25,910	0	121,677	28,979	2,622	(0)	31,601	90,076
47	1820	1820	Distribution Stations	3.33%		11,520	426	22,170	34,116	4,749	1,106	9,401	15,256	18,860
47	1830	1830	Poles, Towers & Fixtures	4.00%		124,750	18,974	(3,615)	140,109	45,497	4,906	1,283	51,686	88,423
47	1835	1835	O/H Cond & Devices	4.00%		157,164	15,849	(2,436)	170,577	81,186	5,813	(4,127)	82,872	87,706
47	1840	1840	U/G Conduit	4.00%		154,310	3,640	(45,537)	112,414	68,209	4,069	(12,692)	59,587	52,827
47	1845	1845	U/G Cond & Devices	4.00%		317,894	16,418	1,399	335,710	165,803	12,163	(12,379)	165,587	170,123
47	1849	1850	Line Transfomers	4.00%		252,332	10,440	0	262,772	131,786	9,370	(4)	141,151	121,621
47	1855	1855	Services (OH and UG)	4.00%		51,542	3,538	50,189	105,268	23,630	3,798	27,915	55,342	49,926
47	1860	1860	Meters	4.00%		39,768	3,097	(26,439)	16,426	19,815	1,461	(22,156)	(880)	17,306
47	1862	1860	Smart Meters	6.67%		9,777	18,285	0	28,061	1,629	3,116	0	4,746	23,316
			Subtotal Distribution Assets			1,276,798	118,479	(41,453)	1,353,824	586,633	48,561	(27,008)	608,186	745,638
General Plant Assets														
13	1870	1870	Leased Property	2.50%		575	0	0	575	575	0	0	575	0
47	1908	1908	Building & Fixtures - Head office	2.00%		27,217	4,538	14,300	46,054	879	919	4,653	6,451	39,603
13	1910	1910	Leasehold Improvements	16.67%	2	2,171	0	(2,171)	0	1,664	89	(1,753)	(0)	0
8	1915	1915	Office Equipment	10.00%		6,933	12	(1,232)	5,712	3,452	476	(1,753)	2,175	3,538
10	1920	1920	Computer hardware	20.00%		16,943	1,211	0	18,154	12,490	1,791	(0)	14,282	3,873
12	1925	1925	Computer Software	33.33%		15,597	2,948	0	18,545	12,712	2,383	0	15,095	3,449
10	1930	1930	Transportation	16.67%	2	21,577	2,604	(1,386)	22,795	13,360	2,424	(1,472)	14,312	8,483
8	1935	1935	Stores Equipment	10.00%		652	0	(464)	187	592	4	(407)	189	(2)
8	1940/1945	1940	Tools, Shop & Garage	10.00%		5,946	415	(19)	6,342	4,066	363	(18)	4,412	1,931
8	1955	1955	Communication Equipment	14.29%	2	1,877	252	0	2,129	597	193	(1)	789	1,340
8	1960	1960	Miscelleneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	1980	System Supervisory Equip	6.67%		18,342	651	0	18,993	10,358	1,034	0	11,392	7,601
47	1990	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
12	1961	1925	Process Re-engineering	33.33%		1,179	614	0	1,793	571	424	0	996	797
			Subtotal General Plant Assets			119,008	13,244	9,028	141,280	61,318	10,100	(750)	70,668	70,612
Other Capital														
47	2005	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	18,280	0	18,280	0	731	0	731	17,549
			Subtotal Other Capital Assets			0	18,280	0	18,280	0	731	0	731	17,549
			Total Assets Before Contributed Capital	n/a		1,395,807	150,003	(32,426)	1,513,384	647,951	59,392	(27,757)	679,585	833,799
47	1995	1995	Contributed Capital	varies		(260,464)	(22,889)	0	(283,353)	(52,097)	(10,630)	15	(62,712)	(220,641)
			NET DISTRIBUTION ASSETS			1,135,342	127,114	(32,426)	1,230,031	595,853	48,762	(27,742)	616,873	613,158

NOTES:

1) Depreciation was recorded on land rights in prior years including 2009. This was removed in 2010 as it was determined that no depreciation should be applied.
2) More then one asset type in the class with different useful lives. Depreciation rate shown is based on the average useful life
3) Review of account balances concluded that a number of accounts required reclassification. These reclassifications were included in this column

FIXED ASSET CONTINUITY SCHEDULE (000's)
YEAR: 2011
CGAAP

APPENDIX 2-B

						COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**PS GL Account**	**GL account to map**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets														
47	1610	1610	Hydro One TS - Contributed Capital	4.00%		0	609	0	609	0	29	0	29	580
n/a	1805/1905	1805	Land	0		10,386	493	0	10,879	0	0	0	0	10,879
CEC	1806/1906	1806	Land Rights	0		731	30	0	761	0	0	0	0	761
47	1808	1808	Building & Fixtures	2.00%		7,171	154	0	7,325	1,238	143	0	1,381	5,945
47	1810	1810	Major spare parts (New 2008)	0		8,404	780	0	9,184	0	440	0	440	8,744
47	1815	1815	Transformer Stations	2.50%		121,677	4,918	0	126,595	31,601	3,071	0	34,671	91,923
47	1820	1820	Distribution Stations	3.33%		34,116	2,648	0	36,764	15,256	1,094	0	16,350	20,414
47	1830	1830	Poles, Towers & Fixtures	4.00%		140,109	13,557	0	153,666	51,686	5,370	0	57,057	96,609
47	1835	1835	O/H Cond & Devices	4.00%		170,577	7,384	0	177,961	82,872	6,057	0	88,929	89,032
47	1840	1840	U/G Conduit	4.00%		112,414	13,282	0	125,696	59,587	4,128	0	63,715	61,980
47	1845	1845	U/G Cond & Devices	4.00%		335,710	14,625	0	350,335	165,587	12,080	0	177,667	172,668
47	1849	1850	Line Transfomers	4.00%		262,772	12,677	0	275,449	141,151	9,267	0	150,419	125,031
47	1855	1855	Services (OH and UG)	4.00%		105,268	4,941	0	110,209	55,342	3,852	0	59,194	51,015
47	1860	1860	Meters	4.00%		16,426	4,170	(2,392)	18,204	(880)	803	(1,877)	(1,954)	20,158
47	1862	1860	Smart Meters	6.67%		28,061	22,970	0	51,031	4,746	3,754	0	8,499	42,532
			Subtotal Distribution Assets			1,353,824	103,237	(2,392)	1,454,668	608,186	50,088	(1,877)	656,397	798,271
General Plant Assets														
13	1870	1870	Leased Property	2.50%		575	0	0	575	575	0	0	575	0
47	1908	1908	Building & Fixtures - Head office	2.00%		46,054	151	0	46,205	6,451	481	0	6,933	39,272
13	1910	1910	Leasehold Improvements	16.67%	1	0	0	0	0	(0)	0	0	(0)	0
8	1915	1915	Office Equipment	10.00%		5,712	100	0	5,813	2,175	477	0	2,652	3,161
10	1920	1920	Computer hardware	20.00%		18,154	1,229	0	19,384	14,282	1,520	0	15,801	3,583
12	1925	1925	Computer Software	33.33%		18,545	6,118	0	24,662	15,095	4,055	0	19,150	5,512
10	1930	1930	Transportation	16.67%	1	22,795	1,145	(1,767)	22,173	14,312	2,531	(1,748)	15,096	7,078
8	1935	1935	Stores Equipment	10.00%		187	0	0	187	189	(0)	0	189	(2)
8	1940/1945	1940	Tools, Shop & Garage	10.00%		6,342	559	0	6,901	4,412	356	0	4,768	2,133
8	1955	1955	Communication Equipment	14.29%	1	2,129	279	0	2,408	789	212	0	1,001	1,407
8	1960	1960	Miscelleneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	1980	System Supervisory Equip	6.67%		18,993	450	0	19,443	11,392	1,022	0	12,414	7,029
47	1990	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
12	1961	1925	Process Re-engineering	33.33%		1,793	(1,793)	0	0	996	(991)	0	5	(5)
			Subtotal General Plant Assets			141,280	8,238	(1,767)	147,751	70,668	9,663	(1,748)	78,583	69,168
Other Capital														
47	2005	2005	Prop. Under Capital Lease-Addiscott	4.00%		18,280	0	0	18,280	731	731	0	1,462	16,818
			Subtotal Other Capital Assets			18,280	0	0	18,280	731	731	0	1,462	16,818
			Total Assets Before Contributed Capital	n/a		1,513,384	111,475	(4,159)	1,620,700	679,585	60,482	(3,625)	736,443	884,257
47	1995	1995	Contributed Capital	varies		(283,353)	(23,545)	0	(306,898)	(62,712)	(11,839)	0	(74,551)	(232,347)
			NET DISTRIBUTION ASSETS			1,230,031	87,930	(4,159)	1,313,802	616,873	48,643	(3,625)	661,891	651,911

NOTES:

1) More then one asset type in the class with different useful life. Depreciation rate shown is based on an average useful life

FIXED ASSET CONTINUITY SCHEDULE ($000's)
YEAR: 2011
MIFRS

APPENDIX 2-B

					COST				**ACCUMULATIVE DEPRECIATION**				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance (3)**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance (3)**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		0	609	0	609	0	29	0	29	580
n/a	1805	Land	0		10,386	581	0	10,968	0	0	0	0	10,968
CEC	1806	Land Rights	0		731	35	0	766	0	0	0	0	766
47	1808	Building & Fixtures	2.50%		5,933	187	0	6,120	0	191	0	191	5,929
47	1810	Major spare parts	0		8,404	780	0	9,184	0	0	0	0	9,184
47	1815	Transformer Stations	2.50%	1	90,076	4,906	0	94,982	0	4,970	(19)	4,951	90,031
47	1820	Distribution Stations	3.33%	1	18,860	2,667	0	21,527	0	2,079	0	2,079	19,448
47	1830	Poles, Towers & Fixtures	2.50%		88,423	12,676	(186)	100,913	0	2,331	0	2,331	98,581
47	1835	O/H Cond & Devices	2.50%		87,706	6,584	(1)	94,289	0	2,776	(171)	2,605	91,684
47	1840	U/G Conduit	2.50%		52,827	10,547	0	63,374	0	1,081	0	1,081	62,293
47	1845	U/G Cond & Devices	2.22%		170,123	15,516	(353)	185,286	0	5,021	218	5,240	180,046
47	1850	Line Transformers	2.92%	1	121,621	12,598	(1,172)	133,047	0	5,782	27	5,809	127,238
47	1855	Services (OH and UG)	3.25%	2	49,926	4,007	0	53,933	0	4,469	0	4,469	49,464
47	1860	Meters	5.33%	2	17,306	3,144	(515)	19,936	0	1,103	(2)	1,101	18,835
47	1860	Smart Meters	6.67%		23,316	23,220	0	46,536	0	3,735	0	3,735	42,801
		Subtotal Distribution Assets	n/a		745,638	98,058	(2,226)	841,470	0	33,566	54	33,620	807,850
General Plant Assets													
13	1870	Leased Property	6.25%		0	0	0	0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	1	39,603	282	0	39,884	0	919	0	919	38,966
13	1910	Leasehold Improvements	6.25%		0	0	0	0	0	0	0	0	0
8	1915	Office Equipment	10.00%		3,538	117	0	3,654	0	473	(10)	462	3,192
10	1920	Computer hardware	20.00%	1	3,873	1,227	0	5,100	0	1,568	0	1,568	3,532
12	1925	Computer Software	25.00%		4,247	4,503	0	8,750	0	2,137	16	2,153	6,597
10	1930	Transportation	8.33%	1	8,483	1,133	(25)	9,590	0	1,267	(74)	1,193	8,397
8	1935	Stores Equipment	10.00%		(2)	(2)	0	(4)	0	(0)	(1)	(2)	(2)
8	1940	Tools, Shop & Garage	10.00%		1,931	597	0	2,528	0	371	6	378	2,150
8	1955	Communication Equipment	25.00%	2	1,340	278	0	1,618	0	398	0	398	1,220
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		7,601	512	(13)	8,099	0	1,452	30	1,482	6,617
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		70,612	8,647	(39)	79,220	0	8,584	(33)	8,551	70,668
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	0	731	0	731	16,818
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	0	731	0	731	16,818
		Total Assets Before Contributed Capital	n/a		833,799	106,705	(2,265)	938,239	0	42,882	21	42,902	895,336
47	1995	Contributed Capital	varies		(220,641)	(23,754)	516	(243,879)	0	(7,383)	(1,056)	(8,439)	(235,441)
		NET DISTRIBUTION ASSETS	n/a		613,158	82,951	(1,749)	694,360	0	35,499	(1,036)	34,462	659,898

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average deprecation rate of the subclasses of assets within the asset group

(3) In accordance with IFRS the MIFRS opening cost balance in the transitional year (2011) shall be the net book value from the prior year closing CGAAP balance(2010).

FIXED ASSET CONTINUITY SCHEDULE ($000's)
YEAR: 2012
MIFRS

APPENDIX 2-B

					COST				**ACCUMULATIVE DEPRECIATION**				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		609	0	0	609	29	32	0	61	548
n/a	1805	Land	0		10,968	0	0	10,968	0	0	0	0	10,968
CEC	1806	Land Rights	0		766	39	0	805	0	0	0	0	805
47	1808	Building & Fixtures	2.50%		6,120	6	0	6,126	191	196	0	387	5,739
47	1810	Major spare parts	0		9,184	0	0	9,184	0	0	0	0	9,184
47	1815	Transformer Stations	2.50%	1	94,982	2,115	0	97,097	4,951	4,299	0	9,249	87,848
47	1820	Distribution Stations	3.33%	1	21,527	298	0	21,825	2,079	1,165	0	3,245	18,580
47	1830	Poles, Towers & Fixtures	2.50%		100,913	11,179	(186)	111,906	2,331	2,637	(4)	4,965	106,941
47	1835	O/H Cond & Devices	2.50%		94,289	11,888	(1)	106,176	2,605	3,062	0	5,667	100,509
47	1840	U/G Conduit	2.50%		63,374	4,271	0	67,645	1,081	1,257	0	2,337	65,308
47	1845	U/G Cond & Devices	2.22%		185,286	24,556	(353)	209,489	5,240	5,547	(6)	10,781	198,708
47	1850	Line Transformers	2.92%	1	133,047	13,542	(1,172)	145,417	5,809	6,266	(32)	12,043	133,374
47	1855	Services (OH and UG)	3.25%	2	53,933	3,697	0	57,630	4,469	3,233	0	7,702	49,928
47	1860	Meters	5.33%	2	19,936	2,556	(85)	22,407	1,101	1,159	0	2,260	20,147
47	1860	Smart Meters	6.67%		46,536	759	0	47,295	3,735	3,417	0	7,152	40,143
		Subtotal Distribution Assets	n/a		841,470	74,906	(1,797)	914,579	33,620	32,270	(42)	65,848	848,731
General Plant Assets													
13	1870	Leased Property	6.25%		0	0	0	0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	1	39,884	1,513	0	41,397	919	939	0	1,858	39,540
13	1910	Leasehold Improvements	6.25%		0	0	0	0	0	0	0	0	0
8	1915	Office Equipment	10.00%		3,654	378	0	4,032	462	494	0	957	3,076
10	1920	Computer hardware	20.00%	1	5,100	3,758	0	8,858	1,568	1,679	0	3,247	5,611
12	1925	Computer Software	25.00%		8,750	1,243	0	9,993	2,153	2,626	0	4,779	5,214
10	1930	Transportation	8.33%	1	9,590	1,958	(63)	11,485	1,193	1,403	(21)	2,575	8,910
8	1935	Stores Equipment	10.00%		(4)	7	0	3	(2)	(0)	0	(2)	5
8	1940	Tools, Shop & Garage	10.00%		2,528	712	0	3,240	378	422	0	799	2,441
8	1955	Communication Equipment	25.00%	2	1,618	336	0	1,954	398	394	0	792	1,162
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		8,099	580	(13)	8,666	1,482	963	(4)	2,441	6,226
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		79,220	10,485	(76)	89,629	8,551	8,919	(25)	17,445	72,184
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	731	733	0	1,464	16,085
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	731	733	0	1,464	16,085
		Total Assets Before Contributed Capital	n/a		938,239	85,391	(1,873)	1,021,757	42,902	41,922	(67)	84,757	937,000
47	1995	Contributed Capital	varies		(243,879)	(15,098)	516	(258,461)	(8,439)	(8,004)	10	(16,432)	(242,029)
		NET DISTRIBUTION ASSETS	n/a		694,360	70,293	(1,357)	763,296	34,462	33,918	(57)	68,325	694,971

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of the subclasses of assets within the asset group

FIXED ASSET CONTINUITY SCHEDULE ($000's)
YEAR: 2013
MIFRS

APPENDIX 2-B

					COST				**ACCUMULATIVE DEPRECIATION**				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		609	0	0	609	61	32	0	93	516
n/a	1805	Land	0		10,968	0	0	10,968	0	0	0	0	10,968
CEC	1806	Land Rights	0		805	41	0	846	0	0	0	0	846
47	1808	Building & Fixtures	2.50%		6,126	15	0	6,141	387	196	0	583	5,558
47	1810	Major spare parts	0		9,184	0	0	9,184	0	0	0	0	9,184
47	1815	Transformer Stations	2.50%	1	97,097	75	0	97,172	9,249	4,179	0	13,429	83,743
47	1820	Distribution Stations	3.33%	1	21,825	4,021	0	25,846	3,245	1,279	0	4,524	21,323
47	1830	Poles, Towers & Fixtures	2.50%		111,906	9,861	0	121,767	4,965	3,038	0	8,003	113,764
47	1835	O/H Cond & Devices	2.50%		106,176	17,940	(26)	124,090	5,667	3,669	(51)	9,285	114,806
47	1840	U/G Conduit	2.50%		67,645	2,957	(155)	70,447	2,337	1,343	0	3,680	66,767
47	1845	U/G Cond & Devices	2.22%		209,489	37,290	(700)	246,079	10,781	6,570	(198)	17,152	228,927
47	1850	Line Transformers	2.92%	1	145,417	11,683	(1,805)	155,295	12,043	6,809	(577)	18,274	137,020
47	1855	Services (OH and UG)	3.25%	2	57,630	3,789	0	61,419	7,702	3,339	0	11,041	50,378
47	1860	Meters	5.33%	2	22,407	3,195	0	25,602	2,260	1,424	0	3,684	21,918
47	1860	Smart Meters	6.67%		47,295	717	0	48,012	7,152	3,481	0	10,633	37,379
		Subtotal Distribution Assets	n/a		914,579	91,584	(2,686)	1,003,477	65,848	35,359	(826)	100,381	903,097
General Plant Assets													
13	1870	Leased Property	6.25%		0	0	0	0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	1	41,397	284	0	41,681	1,858	958	0	2,816	38,866
13	1910	Leasehold Improvements	6.25%		0	0	0	0	0	0	0	0	0
8	1915	Office Equipment	10.00%		4,032	29	0	4,061	957	510	0	1,466	2,595
10	1920	Computer hardware	20.00%	1	8,858	2,014	0	10,872	3,247	2,114	0	5,361	5,510
12	1925	Computer Software	25.00%		9,993	4,405	0	14,398	4,779	2,737	0	7,516	6,882
10	1930	Transportation	8.33%	1	11,485	2,893	(131)	14,247	2,575	1,806	(17)	4,364	9,883
8	1935	Stores Equipment	10.00%		3	0	0	3	(2)	1	0	(2)	4
8	1940	Tools, Shop & Garage	10.00%		3,240	538	0	3,778	799	472	0	1,272	2,506
8	1955	Communication Equipment	25.00%	2	1,954	65	0	2,019	792	420	0	1,213	806
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		8,666	624	0	9,290	2,441	975	0	3,416	5,874
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		89,629	10,852	(131)	100,350	17,445	9,994	(17)	27,422	72,927
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	1,464	731	0	2,195	15,354
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	1,464	731	0	2,195	15,354
		Total Assets Before Contributed Capital	n/a		1,021,757	102,436	(2,817)	1,121,376	84,757	46,084	(843)	129,998	991,378
47	1995	Contributed Capital	varies		(258,461)	(17,734)	525	(275,671)	(16,432)	(8,763)	10	(25,185)	(250,486)
		NET DISTRIBUTION ASSETS	n/a		763,296	84,702	(2,292)	845,705	68,325	37,321	(833)	104,813	740,892

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average depreciation rate of the subclasses of assets within the asset group

(3) Accumulated Depreciation for 2013 includes a full year depreciation on new 2013 additions

Appendix 2-C
Other Operating Revenue

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PowerStream Combined

	Other Operating Revenue	**Historic Actual**				**Bridge Year**	**Test Year**
		2009	**2010**	**2011**	**2011 MIFRS**	**2012 MIFRS**	**MIFRS 2013**
4235	Miscellaneous Service Revenues	4,445,387	4,162,933	3,906,959	3,908,690	3,270,000	3,385,000
4225	Late Payment Charges	2,294,927	2,458,215	2,187,137	2,187,137	2,400,000	2,500,000
4078	SSS Admin charge	839,530	856,269	888,956	888,956	915,600	932,400
4082	Retail Services Revenues	412,435	371,835	327,076	327,076	392,400	399,600
4084	Service Transaction Requests (STR) Revenues	1,820	30	15	15	-	-
4090	Electric Services Incidental to Energy Sales	-	-	-	-	-	-
4205	Interdepartmental Rents	-	-	-	-	-	-
4210	Rent from Electric Property	678,036	708,903	770,366	770,366	700,000	700,000
4215	Other Utility Operating Income	163	396	-	-	-	-
4220	Other Electric Revenues	-	-	-	-	-	-
4324	Special Purpose Charge Recovery	-	291,411	27	27	-	-
4355	Gain on Disposition of Utility and Other Property	218,280	(532,505)	255,701	249,605	-	-
4360	Loss on Disposition of Utility and Other Property	-	-	-	-	-	-
4375	Revenues from Non-Utility Operations	19,165,456	12,993,100	15,787,841	15,787,841	23,213,000	32,211,000
4380	Expenses of Non-Utility Operations	(17,506,265)	(11,437,064)	(13,700,788)	(13,148,290)	(19,600,000)	(28,500,000)
4385	Non-Utility Rental Income	6,417	6,316	8,120	8,120	-	-
4390	Miscellaneous Non-Operating Income	581,064	576,974	685,960	1,414,261	1,020,000	1,020,000
4405	Interest and Dividend Income	583,650	341,915	144,973	144,973	100,800	125,000

"other Revenue - not classified"							
4105	*Transmission Charges Revenue*	-	-	-	-	-	-
4110	*Transmission Services Revenue*	-	-	-	-	-	-
4230	*Sales of Water and Water Power*	-	-	-	-	-	-
4324	*Special Purpose Charge Recovery*	-	291,411	27	27	-	-
4375	*Revenues from Non-Utility Operations*	19,165,456	12,993,100	15,787,841	15,787,841	23,213,000	32,211,000
4380	*Expenses of Non-Utility Operations*	(17,506,265)	(11,437,064)	(13,700,788)	(13,148,290)	(19,600,000)	(28,500,000)
4385	*Non-Utility Rental Income*	6,417	6,316	8,120	8,120	-	-
	subtotal	1,665,608	1,853,763	2,095,199	2,647,697	3,613,000	3,711,000

Revenue offsets *

Specific Service Charges	**4,445,387**	**4,162,933**	**3,906,959**	**3,908,690**	**3,270,000**	**3,385,000**
Late Payment Charges	**2,294,927**	**2,458,215**	**2,187,137**	**2,187,137**	**2,400,000**	**2,500,000**
Other Distribution Revenue	**1,931,984**	**1,937,434**	**1,986,413**	**1,986,413**	**2,008,000**	**2,032,000**
Other Income & Expenses	**1,382,995**	**386,384**	**1,086,634**	**1,808,839**	**1,120,800**	**1,145,000**
Total	**10,055,292**	**8,944,966**	**9,167,142**	**9,891,078**	**8,798,800**	**9,062,000**

**** For Revenue Offsets calculation, the amounts in accounts 4105,4110,4230, 4324 ,4375,4380,4385 are not included in Other Income and Expenses .***

***** The amounts in account 4405 are net of interest on Regulatory Assets and interest on Customer Deposits***

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Appendix 2-C
Other Operating Revenue

Other Distribution Revenue and Other Income - detailed breakdown

Selected Accounts*

PowerStream Combined

		Historic Actual				Bridge Year	Test Year
		2009	2010	2011	2011 MIFRS	2012 MIFRS	2013 MIFRS
4405	**Interest and Dividend Income**						
	Bank deposit Interest	(551,708)	(213,887)	(144,973)	(144,973)	(100,800)	(125,000)
	Interest on regulatory Assets	306,156	(65,226)	324,602	324,602	-	-
	Tax Assessment	(28,280)	(128,028)	-	-	-	-
	Interest - MAR	2,024					
	Interest on Customer deposits	(50,000)	(90,000)	(145,000)	(145,000)	(150,000)	(225,000)
	Discounts earned	(5,686)					
	Total	(327,494)	(497,141)	34,629	34,629	(250,800)	(350,000)
	Less Interest on Reg. Assets	(306,156)	65,226	(324,602)	(324,602)	-	-
	Less Interest on Customer deposits	50,000	90,000	145,000	145,000	150,000	225,000
	Total included in Revenue Offsets	**(583,650)**	**(341,915)**	**(144,973)**	**(144,973)**	**(100,800)**	**(125,000)**

		Historic Actual				Bridge Year	Test Year
		2009	2010	2011	2011 MIFRS	2012 MIFRS	2013 MIFRS
4390	**Miscellaneous Non-Operating Income**						
	Sale of scrap	(175,743)	(294,610)	(265,948)	(265,948)	(200,000)	(200,000)
	Damage claims	(102,965)	(67,786)	(91,703)	(820,004)	(700,000)	(700,000)
	Miscellaneous	(302,356)	(214,578)	(328,309)	(328,309)	(120,000)	(120,000)
	Total	(581,064)	(576,974)	(685,960)	(1,414,261)	(1,020,000)	(1,020,000)

Note:
PowerStream does not manage most of Other Revenue accounts on the level below the GL account.

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Appendix 2-E
Summary of OM&A Expenses

Table 1: OM&A Year-over-Year Comparisons

	2009	2009	Variance	Percentage Change
	Board-approved (PowerStream South)	Actuals (PowerStream Combined)	$	%
Operations	$ 9,418,016	$ 13,361,537	$ 3,943,521	41.87%
Maintenance	$ 6,470,562	$ 9,318,936	$ 2,848,374	44.02%
Billing and Collecting	$ 7,791,992	$ 9,965,156	$ 2,173,164	27.89%
Community Relations	$ 698,475	$ 1,093,831	$ 395,357	56.60%
Administrative and General	$ 18,837,255	$ 25,937,666	$ 7,100,411	37.69%
Total OM&A Expenses	$ 43,216,300	$ 59,677,127	$ 16,460,827	38.09%
Inflation Rate				1.30%

	2009	2010	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 13,361,537	$ 10,831,471	-$ 2,530,066	-18.94%
Maintenance	$ 9,318,936	$ 8,488,612	-$ 830,324	-8.91%
Billing and Collecting	$ 9,965,156	$ 11,924,541	$ 1,959,385	19.66%
Community Relations	$ 1,093,831	$ 1,331,860	$ 238,028	21.76%
Administrative and General	$ 25,937,666	$ 24,261,244	-$ 1,676,422	-6.46%
Total OM&A Expenses	$ 59,677,127	$ 56,837,729	-$ 2,839,399	-4.76%
Inflation Rate				1.30%

	2010	2011	Variance	Percentage Change
	Actuals	Actuals (CGAAP)	$	%
Operations	$ 10,831,471	$ 12,292,411	$ 1,460,940	13.49%
Maintenance	$ 8,488,612	$ 9,236,005	$ 747,393	8.80%
Billing and Collecting	$ 11,924,541	$ 12,516,572	$ 592,031	4.96%
Community Relations	$ 1,331,860	$ 2,167,950	$ 836,090	62.78%
Administrative and General	$ 24,261,244	$ 25,873,793	$ 1,612,549	6.65%
Total OM&A Expenses	$ 56,837,729	$ 62,086,731	$ 5,249,002	9.24%
Inflation Rate				2.00%

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Appendix 2-E
Summary of OM&A Expenses

	2011 Actuals (CGAAP)	2011 Actuals (MIFRS)	Variance $	Percentage Change %
Operations	$ 12,292,411	$ 19,579,408	$ 7,286,997	59.28%
Maintenance	$ 9,236,005	$ 7,350,509	-$ 1,885,496	-20.41%
Billing and Collecting	$ 12,516,572	$ 15,652,528	$ 3,135,956	25.05%
Community Relations	$ 2,167,950	$ 2,073,905	-$ 94,044	-4.34%
Administrative and General	$ 25,873,793	$ 29,229,011	$ 3,355,217	12.97%
Total OM&A Expenses	$ 62,086,731	$ 73,885,361	$ 11,798,630	19.00%
Inflation Rate				2.00%

	2011 Actuals (MIFRS)	2012 Forecast (MIFRS)	Variance $	Percentage Change %
Operations	$ 19,579,408	$ 23,616,751	$ 4,037,343	20.62%
Maintenance	$ 7,350,509	$ 7,027,380	-$ 323,129	-4.40%
Billing and Collecting	$ 15,652,528	$ 14,615,393	-$ 1,037,135	-6.63%
Community Relations	$ 2,073,905	$ 1,172,518	-$ 901,387	-43.46%
Administrative and General	$ 29,229,011	$ 35,163,637	$ 5,934,627	20.30%
Total OM&A Expenses	$ 73,885,361	$ 81,595,680	$ 7,710,318	10.44%
Inflation Rate				2.00%

	2012 Forecast (MIFRS)	2013 Forecast (MIFRS)	Variance $	Percentage Change %
Operations	$ 23,616,751	$ 24,964,005	$ 1,347,253	5.70%
Maintenance	$ 7,027,380	$ 7,636,633	$ 609,252	8.67%
Billing and Collecting	$ 14,615,393	$ 15,756,981	$ 1,141,588	7.81%
Community Relations	$ 1,172,518	$ 1,264,602	$ 92,084	7.85%
Administrative and General	$ 35,163,637	$ 36,078,880	$ 915,243	2.60%
Total OM&A Expenses	$ 81,595,680	$ 85,701,101	$ 4,105,421	5.03%
Inflation Rate				2.00%

Table 2: Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison

	2011 Actuals	2013 Forecast	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 73,885,361	$ 85,701,101	$ 11,815,740	15.99%

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Appendix 2-E
Summary of OM&A Expenses

	2009 Board-approved	2013 Forecast	Variance $	Percentage Change %
Test Year versus LRY Board-approved	$ 43,216,300	$ 85,701,101	$ 42,484,801	98.31%
Simple average of % variance for all years				7.79%
Compound annual growth rate for all years				126%

Note 1 The comparison between 2009 Board Approved and 2013 Test year is **not valid**, due to:

1. 2009 Board Approved amounts are for PowerStream South only; the rest of years are for PowerStream Combined
2. The overall increase in OM&A includes the increase due to the transition to IFRS

The IFRS impact amounts to $11,798,630 and shown separately in table comparing 2011 CGAAP to 2011 MIFRS.

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Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account	Description	2009 Actual	2010 Actual	2011 Actual (CGAAP)	2011 Actual (MIFRS)	2012 Bridge Year	2013 Test Year
Operations							
5005	Operation Supervision and Engineering	$ 1,486,553	$ 447,286	$ 42,483	$ 7,769,885	$ 8,100,774	$ 8,609,802
5010	Load Dispatching	$ 2,579,484	$ 2,852,958	$ 3,384,605	$ 3,279,023	$ 3,138,721	$ 3,243,717
5012	Station Buildings and Fixtures Expense	$ 565,513	$ 297,789	$ 147,889	$ 110,184	$ -	$ -
5014	Transformer Station Equipment - Operation Labour	$ 128,227	$ 46,325	$ 425,125	$ 308,720	$ 368,917	$ 423,291
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 4,441	$ 517	$ 532	$ 404	$ 97,855	$ 97,487
5016	Distribution Station Equipment - Operation Labour	$ 170,417	$ 332,254	$ 409,927	$ 1,196,539	$ 1,476,418	$ 1,590,179
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 15,524	$ 33,214	$ 62,538	$ 55,394	$ 309,064	$ 296,096
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 1,863,369	$ 836,130	$ 1,210,001	$ 815,593	$ 783,108	$ 795,256
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 377,498	$ 488,574	$ 413,356	$ 418,879	$ -	$ -
5030	Overhead Sub-transmission Feeders - Operation	$ 155,454	$ -	-$ 391	-$ 371	$ -	$ -
5035	Overhead Distribution Transformers - Operation	$ 46,538	$ 34,821	$ 49,384	$ 36,132	$ 1,189,539	$ 1,492,466
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 800,835	$ 597,925	$ 615,280	$ 420,749	$ 487,840	$ 498,302
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 183,956	$ 305,776	$ 426,212	$ 426,031	$ 704,917	$ 705,151
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5055	Underground Distribution Transformers - Operation	$ 90,382	$ 86,774	$ 73,128	$ 49,767	$ 232,683	$ 237,914
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 2,016,932	$ 1,334,321	$ 1,403,475	$ 1,654,650	$ 3,358,106	$ 3,385,695
5070	Customer Premises - Operation Labour	$ 1,874,703	$ 1,882,702	$ 1,911,309	$ 1,321,511	$ 1,389,870	$ 1,431,431
5075	Customer Premises - Operation Materials and Expenses	$ 912,392	$ 981,920	$ 1,373,411	$ 1,372,173	$ 1,467,940	$ 1,527,217
5085	Miscellaneous Distribution Expenses	$ 983	$ 26,415	$ 108,629	$ 108,629	$ 250,000	$ 400,000
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 65,515	$ 94,141	$ 68,099	$ 68,099	$ 80,000	$ 80,000
5096	Other Rent	$ 22,822	$ 151,628	$ 167,417	$ 167,417	$ 181,000	$ 150,000
Total - Operations		$ 13,361,537	$ 10,831,471	$ 12,292,411	$ 19,579,408	$ 23,616,751	$ 24,964,005
Account	**Description**	**2009 Actual**	**2010 Actual**	**2011 Actual (CGAAP)**	**2011 Actual (MIFRS)**	**2012 Bridge Year**	**2013 Test Year**
Maintenance							
5105	Maintenance Supervision and Engineering	$ 382,045	$ 12,801	$ 15,739	$ 13,521	$ -	$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ 86,545	$ 70,034	$ -	$ -
5112	Maintenance of Transformer Station Equipment	$ 646,223	$ 611,983	$ 352,050	$ 244,628	$ 228,173	$ 253,627
5114	Maintenance of Distribution Station Equipment	$ 438,509	$ 355,572	$ 492,815	$ 371,602	$ 255,871	$ 521,275
5120	Maintenance of Poles, Towers and Fixtures	$ 617,048	$ 375,491	$ 302,076	$ 221,489	$ 182,166	$ 184,777
5125	Maintenance of Overhead Conductors and Devices	$ 2,215,523	$ 1,568,593	$ 2,339,695	$ 1,868,502	$ 1,928,140	$ 1,968,169
5130	Maintenance of Overhead Services	$ 345,033	$ 345,566	$ 372,922	$ 262,426	$ 250,957	$ 256,649
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 355,777	$ 991,570	$ 1,215,673	$ 1,101,652	$ 103,103	$ 105,390
5145	Maintenance of Underground Conduit	$ 16,688	$ 6,579	$ 9,951	$ 6,217	$ 1,665	$ 1,665
5150	Maintenance of Underground Conductors and Devices	$ 3,520,437	$ 3,392,349	$ 2,989,356	$ 2,432,846	$ 3,335,421	$ 3,600,600
5155	Maintenance of Underground Services	$ 353,266	$ 450,365	$ 725,054	$ 503,923	$ 501,422	$ 499,390
5160	Maintenance of Line Transformers	$ 428,387	$ 337,507	$ 333,925	$ 253,465	$ 240,463	$ 245,090
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -

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Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

5175	Maintenance of Meters	$ -	$ 40,237	$ 204	$ 204	$ -	$ -
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance		$ 9,318,936	$ 8,488,612	$ 9,236,005	$ 7,350,509	$ 7,027,380	$ 7,636,633
Account	**Description**	**2009 Actual**	**2010 Actual**	**2011 Actual (CGAAP)**	**2011 Actual (MIFRS)**	**2012 Bridge Year**	**2013 Test Year**
Billing and Collecting							
5305	Supervision	$ 654,094	$ 567,030	$ 1,344,097	$ 1,441,809	$ 1,500,346	$ 1,693,462
5310	Meter Reading Expense	$ 2,280,044	$ 4,163,571	$ 2,741,828	$ 3,156,370	$ 1,124,885	$ 1,157,296
5315	Customer Billing	$ 2,728,518	$ 2,940,784	$ 3,796,816	$ 5,815,198	$ 6,356,534	$ 7,015,483
5320	Collecting	$ 1,389,848	$ 2,290,521	$ 2,793,283	$ 3,398,603	$ 3,548,627	$ 3,764,039
5325	Collecting - Cash Over and Short	$ 908	-$ 1,742	$ 480	$ 480	$ -	$ -
5330	Collection Charges	$ 38,444	$ 53,414	$ 59,000	$ 59,000	$ -	$ -
5335	Bad Debt Expense	$ 2,873,302	$ 1,910,962	$ 1,781,069	$ 1,781,069	$ 2,085,000	$ 2,126,700
5340	Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -	$ -
Total - Billing and Collecting		$ 9,965,156	$ 11,924,541	$ 12,516,572	$ 15,652,528	$ 14,615,393	$ 15,756,981
Account	**Description**	**2009 Actual**	**2010 Actual**	**2011 Actual (CGAAP)**	**2011 Actual (MIFRS)**	**2012 Bridge Year**	**2013 Test Year**
Community Relations							
5405	Supervision	$ 376,569	$ 468,587	$ 682,730	$ 660,761	$ 754,260	$ 838,998
5410	Community Relations - Sundry	$ 568,444	$ 594,488	$ 1,418,296	$ 1,413,144	$ 418,257	$ 425,604
5415	Energy Conservation	$ 9,667	$ 268,327	$ 66,924	$ 0	$ -	$ -
5420	Community Safety Program	$ 139,152	$ 458	$ -	$ -	$ -	$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5505	Supervision	$ -	$ -	$ -	$ -	$ -	$ -
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -	$ -
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -
Total - Community Relations		$ 1,093,831	$ 1,331,860	$ 2,167,950	$ 2,073,905	$ 1,172,518	$ 1,264,602
Account	**Description**	**2009 Actual**	**2010 Actual**	**2011 Actual (CGAAP)**	**2011 Actual (MIFRS)**	**2012 Bridge Year**	**2013 Test Year**
Administrative and General Expenses							
5605	Executive Salaries and Expenses	$ 3,229,300	$ 4,067,329	$ 3,530,641	$ 4,049,642	$ 4,000,690	$ 4,176,861
5610	Management Salaries and Expenses	$ 3,658,965	$ 4,274,054	$ 4,558,388	$ 8,224,723	$ 9,108,697	$ 9,874,777
5615	General Administrative Salaries and Expenses	$ 1,730,289	$ 1,698,893	$ 1,448,206	$ 1,995,430	$ 1,987,392	$ 2,052,903
5620	Office Supplies and Expenses	$ 1,424,212	$ 280,684	$ 752,981	$ 752,981	$ 1,028,050	$ 1,288,086
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -	$ -
5630	Outside Services Employed	$ 2,630,476	$ 897,896	$ 1,362,003	$ 1,362,044	$ 2,045,800	$ 1,376,840
5635	Property Insurance	$ 61,616	$ 2,041	$ -	$ -	$ 21,931	$ 30,000
5640	Injuries and Damages	$ 1,112,170	$ 1,237,301	$ 1,618,214	$ 1,618,214	$ 1,458,451	$ 1,808,025
5645	Employee Pensions and Benefits	-$ 147,905	$ 1,057,252	-$ 174,071	-$ 305,561	$ 288,000	$ 296,640
5650	Franchise Requirements	$ -	$ -	$ -	$ -	$ -	$ -
5655	Regulatory Expenses	$ 1,384,907	$ 1,199,956	$ 1,236,537	$ 1,236,537	$ 1,364,500	$ 1,396,665
5660	General Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5665	Miscellaneous General Expenses	$ 7,775,923	$ 5,535,358	$ 6,348,193	$ 6,938,100	$ 9,442,413	$ 10,434,519
5670	Rent	$ 256,722	$ 7,795	$ 499,875	$ 1,003,875	$ 1,232,423	$ 1,266,677
5675	Maintenance of General Plant	$ 928,665	$ 1,557,403	$ 1,518,481	$ 2,356,865	$ 2,614,127	$ 2,829,037
5680	Electrical Safety Authority Fees	$ -	$ -	$ -	$ -	$ -	$ -

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Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

5685 Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -	$ -
5695 OM&A Contra Account	$ 901,322	$ 1,047,116	$ 1,543,831	$ 1,543,831	$ 1,333,236	$ -
6205 Donations (Charitable Contributions)	$ 30,000	$ 336,289	$ 412,009	$ 412,009	$ 350,000	$ 350,000
JS less Cost of Shared service (included in A&G above)	$ -	$ -	$ -	-$ 3,568,659	-$ 2,843,108	-$ 2,928,402
Total - Administrative and General Expenses	$ 24,976,662	$ 23,199,367	$ 24,655,287	$ 27,620,031	$ 33,432,602	$ 34,252,629
Other Distribution Expenses						
6105 Taxes Other Than Income Taxes	$ 947,459	$ 1,061,756	$ 1,212,882	$ 1,603,355	$ 1,700,435	$ 1,795,039
6215 Penalties	$ 13,544	$ 121	$ 5,624	$ 5,624	$ 30,600	$ 31,212
6225 Other Deductions	$ -	$ -	$ -	$ -	$ -	$ -
Total - Other Distribution Expenses	$ 961,004	$ 1,061,877	$ 1,218,506	$ 1,608,979	$ 1,731,035	$ 1,826,251
Total OM&A	$ 59,677,127	$ 56,837,729	$ 62,086,731	$ 73,885,361	$ 81,595,680	$ 85,701,101

Note:

If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

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Appendix 2-G
OM&A Cost Driver Table

OM&A	**2009 Board Approved**	**2009 CGAAP**	**2010 CGAAP**	**2011 CGAAP**	**2011**	**2012**	**2013**
Opening Balance	$ 43,216	$ 49,832	$ 59,677	$ 56,838	$ 62,086	$ 73,887	$ 81,596
Barrie costs in 2009		$ 9,845					
IFRS			$ -	$ -	$ 11,801	$ 725	-$ 85
Compensation	$ 1,261		-$ 110	-$ 1,014	$ -	$ 2,471	$ 1,667
Additional Staff	$ -		$ 315	$ 628	$ -	$ 645	$ 1,038
Asset Maintenance	$ 1,665		-$ 1,186	$ 1,422	$ -	$ 1,303	$ 335
Smart Meter	$ -		$ 2,522	$ 1,104	$ -	-$ 895	$ -
Customer Services / Regulatory	$ 1,279		-$ 962	$ 729	$ -	$ 1,258	-$ 252
IS Strategy	$ -		$ -	$ 483	$ -	$ 856	$ 180
Locates	$ 536		$ 56	$ 459	$ -	$ -	$ 140
Corporate Development	$ -		$ -	$ 586	$ -	$ 465	$ 200
Insurance	$ -		$ -	$ 379	$ -	$ -	$ 358
Other	$ 1,875		-$ 3,474	$ 472	$ -	$ 881	$ 524
Closing Balance	$ 49,832	$ 59,677	$ 56,838	$ 62,086	$ 73,887	$ 81,596	$ 85,701

Notes:

(1) The detailed explanation for each cost driver and associated amount is provided In Exhibit D1, Tab 1, Schedule 1

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Appendix 2-H
Regulatory Cost Schedule

	Regulatory Cost Category	**USoA Account**	**USoA Account**	**Ongoing or One-time Cost? 2**	**2009**	**2010**	**2011**	**Bridge Year 2012**	**Annual % Change**	**Test Year 2013**	**Annual % Change**
	(A)	(B)	(C)	(D)	(E)	(F)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655.4565		On-Going	$ 992,906	$ 1,001,353	$ 1,010,494	$ 1,102,500	9.11%	$ 1,157,625	5.00%
2	OEB Hearing Assessments (applicant-originated)	5665-1265		One-Time	$ 203,925	$ 3,960	$ 5,115	$ 170,000	3223.56%	$ 110,000	-35.29%
3	OEB Section 30 Costs (OEB-initiated)	5665-1265		On-Going	$ 50,303	$ 31,954	$ 45,713	$ 80,000	75.00%	$ 50,000	-37.50%
4	Expert Witness costs for regulatory matters			One-Time	$ -	$ -	$ -	$ -	0.00%	$ -	0.00%
5	Legal costs for regulatory matters (2)	5630-1262		One-Time	$ 722,072	$ 39,251	$ 59,420	$ 610,000	926.58%	$ 110,000	-81.97%
6	Consultants' costs for regulatory matters (2)	5630-1261		One-Time	$ 125,346	$ 81,241	$ 86,403	$ 150,000	73.61%	$ 50,000	-66.67%
7	Operating expenses associated with staff resources allocated to regulatory matters	5610-xxxx 5655-xxxx		On-Going	$ 608,738	$ 558,275	$ 681,661	$ 688,557	1.01%	$ 769,377	11.74%
8	Operating expenses associated with other resources allocated to regulatory matters [1]			On-Going							
9	Other regulatory agency fees or assessments (ESA)	9083		On-Going	$ 104,282	$ 134,543	$ 136,989	$ 139,000	1.47%	$ 141,000	1.44%
10	Any other costs for regulatory matters (please define)										
11	Intervenor costs										
12	Sub-total - Ongoing Costs [3]		$ -		$ 1,756,230	$ 1,726,125	$ 1,874,857	$ 2,010,057	7.21%	$ 2,118,002	5.37%
13	Sub-total - One-time Costs [4]		$ -		$ 1,051,343	$ 124,452	$ 150,938	$ 930,000	516.15%	$ 270,000	-70.97%
14	Total		$ -		$ 2,807,573	$ 1,850,578	$ 2,025,795	$ 2,940,057	45.13%	$ 2,388,002	-18.78%

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PowerStream

2013 EDR Model

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Appendix 2-I
OM&A Cost per Customer and per FTEE

	2008 Barrie Hydro	2009 PowerStream South	PowerStream Combined					
			2009 - Actual	2010 Actual	2011 CGAAP	2011 MIFRS	2012 Bridge Year	2013 Test Year
	Board Approved		Actual				Forecast	
Number of Customers	71,079	247,895	317,475	324,595	332,135	332,135	339,452	346,725
Total OM&A from Appendix 2-G	$ 10,047,532	$ 43,216,300	$ 59,677,127	$ 56,837,729	$ 62,086,731	$ 73,885,361	$ 81,595,680	$ 85,701,101
OM&A cost per customer	$ 141.4	$ 174.3	$ 188.0	$ 175.1	$ 186.9	$ 222.5	$ 240.4	$ 247.2
Number of FTEEs	123	434	516	528	529	529	549	570
Customers/FTEEs	578	572	615	615	628	628	618	608
OM&A Cost per FTEE	$ 81,687	$ 99,646	$ 115,653	$ 107,647	$ 117,366	$ 139,670	$ 148,626	$ 150,353

Notes:

(1) Barrie Hydro filed cost of service application in 2007; PowerStream filed COS application in 2008. The "approved" information in the table above is from two separate COS applications.

(2) The number of customers is mid-year average - actual data for 2009-2011 and customer forecast for 2012-2013. For this table, Street Light Customers (not Street Light Connections) are included in total. The sentinel connections are excluded from total customer count, similar to the calcualtion in Annual Yearbooks

(3) The number of FTEs is as per Appendix 2-K.

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Appendix 2-J
OM&A Variance Analysis
(excluding Depreciation and Amortization)

		Last Board-approved Rebasing Year (2008 Barrie HYdro)	**Last Board-approved Rebasing Year (2009 PowerStream South)**	**Most Current Actual Year (2011 MIFRS)**	**Test Year (2013)**	**Test Year Versus Last Rebasing (PowerStream South)**		**Test Year Versus Most Current Actuals**	
Account	**Description**					**Variance ($)**	**Percentage Change (%)**	**Variance ($)**	**Percentage Change (%)**
Operations									
5005	Operation Supervision and Engineering	$ 1,017,428	$ -	$ 7,769,885	$ 8,609,802	$ 8,609,802		$ 839,917	10.81%
5010	Load Dispatching	$ 208,745	$ 2,495,564	$ 3,279,023	$ 3,243,717	$ 748,153	29.98%	-$ 35,306	-1.08%
5012	Station Buildings and Fixtures Expense	$ 189,285	$ 292,238	$ 110,184	$ -	-$ 292,238	-100.00%	-$ 110,184	-100.00%
5014	Transformer Station Equipment - Operation Labour	$ -	$ 527,297	$ 308,720	$ 423,291	-$ 104,006	-19.72%	$ 114,571	37.11%
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ 94,735	$ 404	$ 97,487	$ 2,752	2.90%	$ 97,083	24030.45%
5016	Distribution Station Equipment - Operation Labour	$ 146,609	$ 237,540	$ 1,196,539	$ 1,590,179	$ 1,352,639	569.44%	$ 393,639	32.90%
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 153,186	$ 111,428	$ 55,394	$ 296,096	$ 184,668	165.73%	$ 240,702	434.52%
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 201,259	$ 496,263	$ 815,593	$ 795,256	$ 298,993	60.25%	-$ 20,336	-2.49%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 133,488	$ 688,772	$ 418,879	$ -	-$ 688,772	-100.00%	-$ 418,879	-100.00%
5030	Overhead Sub-transmission Feeders - Operation	$ 102,858	$ -	-$ 371	$ -	$ -		$ 371	-100.00%
5035	Overhead Distribution Transformers - Operation	$ 326	$ 46,919	$ 36,132	$ 1,492,466	$ 1,445,547	3080.93%	$ 1,456,334	4030.54%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 81,273	$ 153,787	$ 420,749	$ 498,302	$ 344,515	224.02%	$ 77,553	18.43%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 45,309	$ 437,979	$ 426,031	$ 705,151	$ 267,172	61.00%	$ 279,120	65.52%
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ 5,136	$ 182,749	$ 49,767	$ 237,914	$ 55,165	30.19%	$ 188,147	378.06%
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 319,349	$ 1,305,362	$ 1,654,650	$ 3,385,695	$ 2,080,334	159.37%	$ 1,731,046	104.62%
5070	Customer Premises - Operation Labour	$ -	$ 1,449,087	$ 1,321,511	$ 1,431,431	-$ 17,656	-1.22%	$ 109,919	8.32%
5075	Customer Premises - Operation Materials and Expenses	$ -	$ 855,798	$ 1,372,173	$ 1,527,217	$ 671,420	78.46%	$ 155,045	11.30%
5085	Miscellaneous Distribution Expenses	$ 62,566	$ -	$ 108,629	$ 400,000	$ 400,000		$ 291,371	268.22%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 12,600	$ -	$ 68,099	$ 80,000	$ 80,000		$ 11,901	17.48%
5096	Other Rent	$ -	$ 42,500	$ 167,417	$ 150,000	$ 107,500	252.94%	-$ 17,417	-10.40%
Total - Operations		**$ 2,679,417**	**$ 9,418,016**	**$ 19,579,408**	**$ 24,964,005**	**$ 15,545,988**	**165.07%**	**$ 5,384,597**	**27.50%**
Account	**Description**								
Maintenance									
5105	Maintenance Supervision and Engineering	$ 694,228	$ -	$ 13,521	$ -	$ -		-$ 13,521	-100.00%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 184,843	$ -	$ 70,034	$ -	$ -		-$ 70,034	-100.00%
5112	Maintenance of Transformer Station Equipment	$ -	$ 602,195	$ 244,628	$ 253,627	-$ 348,569	-57.88%	$ 8,999	3.68%
5114	Maintenance of Distribution Station Equipment	$ 183,255	$ 501,294	$ 371,602	$ 521,275	$ 19,982	3.99%	$ 149,673	40.28%
5120	Maintenance of Poles, Towers and Fixtures	$ 21,713	$ 211,559	$ 221,489	$ 184,777	-$ 26,783	-12.66%	-$ 36,713	-16.58%
5125	Maintenance of Overhead Conductors and Devices	$ 21,713	$ 1,667,824	$ 1,868,502	$ 1,968,169	$ 300,345	18.01%	$ 99,667	5.33%
5130	Maintenance of Overhead Services	$ 83,439	$ 109,956	$ 262,426	$ 256,649	$ 146,693	133.41%	-$ 5,777	-2.20%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 345,260	$ 350,000	$ 1,101,652	$ 105,390	-$ 244,610	-69.89%	-$ 996,262	-90.43%
5145	Maintenance of Underground Conduit	$ 79,115	$ 24,284	$ 6,217	$ 1,665	-$ 22,618	-93.14%	-$ 4,551	-73.21%
5150	Maintenance of Underground Conductors and Devices	$ 79,115	$ 1,483,260	$ 2,432,846	$ 3,600,600	$ 2,117,340	142.75%	$ 1,167,754	48.00%
5155	Maintenance of Underground Services	$ -	$ 1,222,913	$ 503,923	$ 499,390	-$ 723,523	-59.16%	-$ 4,533	-0.90%
5160	Maintenance of Line Transformers	$ 21,850	$ 297,277	$ 253,465	$ 245,090	-$ 52,187	-17.56%	-$ 8,375	-3.30%
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ 137,448	$ -	$ 204	$ -	$ -		-$ 204	-100.00%
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		**$ 1,851,979**	**$ 6,470,562**	**$ 7,350,509**	**$ 7,636,633**	**$ 1,166,070**	**18.02%**	**$ 286,123**	**3.89%**
Account	**Description**								
Billing and Collecting									

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Appendix 2-J
OM&A Variance Analysis
(excluding Depreciation and Amortization)

Account	**Description**	**Last Board-approved Rebasing Year (2008 Barrie HYdro)**	**Last Board-approved Rebasing Year (2009 PowerStream South)**	**Most Current Actual Year (2011 MIFRS)**	**Test Year (2013)**	**Test Year Versus Last Rebasing (PowerStream South)**		**Test Year Versus Most Current Actuals**	
						Variance ($)	**Percentage Change (%)**	**Variance ($)**	**Percentage Change (%)**
5305	Supervision	$ 115,594	$ 1,006,652	$ 1,441,809	$ 1,693,462	$ 686,810	68.23%	$ 251,654	17.45%
5310	Meter Reading Expense	$ 379,197	$ 2,821,326	$ 3,156,370	$ 1,157,296	-$ 1,664,030	-58.98%	-$ 1,999,074	-63.33%
5315	Customer Billing	$ 706,214	$ 870,031	$ 5,815,198	$ 7,015,483	$ 6,145,452	706.35%	$ 1,200,286	20.64%
5320	Collecting	$ 177,206	$ 1,857,982	$ 3,398,603	$ 3,764,039	$ 1,906,058	102.59%	$ 365,437	10.75%
5325	Collecting - Cash Over and Short	$ -	$ -	$ 480	$ -	$ -		-$ 480	-100.00%
5330	Collection Charges	$ -	$ -	$ 59,000	$ -	$ -		-$ 59,000	-100.00%
5335	Bad Debt Expense	$ 163,040	$ 1,236,000	$ 1,781,069	$ 2,126,700	$ 890,700	72.06%	$ 345,631	19.41%
5340	Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Billing and Collecting		**$ 1,541,251**	**$ 7,791,992**	**$ 15,652,528**	**$ 15,756,981**	**$ 7,964,989**	**102.22%**	**$ 104,453**	**0.67%**
Account	**Description**								
Community Relations									
5405	Supervision	$ -	$ 305,375	$ 660,761	$ 838,998	$ 533,624	174.74%	$ 178,237	26.97%
5410	Community Relations - Sundry	$ -	$ 329,000	$ 1,413,144	$ 425,604	$ 96,604	29.36%	-$ 987,540	-69.88%
5415	Energy Conservation	$ -	$ 64,100	$ 0	$ -	-$ 64,100	-100.00%	-$ 0	-100.00%
5420	Community Safety Program	$ 221,149	$ -	$ -	$ -	$ -		$ -	
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		**$ 221,149**	**$ 698,475**	**$ 2,073,905**	**$ 1,264,602**	**$ 566,128**	**81.05%**	**-$ 809,303**	**-39.02%**
Account	**Description**								
Administrative and General Expenses									
5605	Executive Salaries and Expenses	$ 525,032	$ 3,705,126	$ 4,049,642	$ 4,176,861	$ 471,734	12.73%	$ 127,219	3.14%
5610	Management Salaries and Expenses	$ 652,598	$ 3,935,182	$ 8,224,723	$ 9,874,777	$ 5,939,596	150.94%	$ 1,650,054	20.06%
5615	General Administrative Salaries and Expenses	$ 1,577,216	$ 967,129	$ 1,995,430	$ 2,052,903	$ 1,085,774	112.27%	$ 57,473	2.88%
5620	Office Supplies and Expenses	$ 283,919	$ 1,126,848	$ 752,981	$ 1,288,086	$ 161,238	14.31%	$ 535,105	71.06%
5625	Administrative Expense Transferred - Credit	-$ 772,114	$ -	$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 889,182	$ 1,943,205	$ 1,362,044	$ 1,376,840	-$ 566,365	-29.15%	$ 14,796	1.09%
5635	Property Insurance	$ 67,412	$ 58,416	$ -	$ 30,000	-$ 28,416	-48.64%	$ 30,000	
5640	Injuries and Damages	$ 148,035	$ 924,000	$ 1,618,214	$ 1,808,025	$ 884,025	95.67%	$ 189,811	11.73%
5645	Employee Pensions and Benefits	$ -	$ -	-$ 305,561	$ 296,640	$ 296,640		$ 602,201	-197.08%
5650	Franchise Requirements	$ -	$ -	$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ 220,000	$ 1,512,800	$ 1,236,537	$ 1,396,665	-$ 116,135	-7.68%	$ 160,128	12.95%
5660	General Advertising Expenses	$ -	$ -	$ -	$ -	$ -		$ -	
5665	Miscellaneous General Expenses	-$ 249,479	$ 3,524,803	$ 6,938,100	$ 10,434,519	$ 6,909,716	196.03%	$ 3,496,419	50.39%
5670	Rent	$ -	$ 274,728	$ 1,003,875	$ 1,266,677	$ 991,949	361.07%	$ 262,802	26.18%
5675	Maintenance of General Plant	$ -	$ 710,159	$ 2,356,865	$ 2,829,037	$ 2,118,878	298.37%	$ 472,172	20.03%
5680	Electrical Safety Authority Fees	$ 40,000	$ -	$ -	$ -	$ -		$ -	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -		$ -	
5695	OM&A Contra Account	$ -	-$ 1,004,750	$ 1,543,831	$ -	$ 1,004,750	-100.00%	-$ 1,543,831	-100.00%
6205	Donations (Charitable Contributions)	$ -	$ 41,000	$ 412,009	$ 350,000	$ 309,000	753.66%	-$ 62,009	-15.05%
JS	Reclassification of Joint Service Costs			-$ 3,568,659	-$ 2,928,402				
Total - Administrative and General Expenses		**$ 3,381,801**	**$ 17,718,646**	**$ 27,620,031**	**$ 34,252,629**	**$ 19,462,385**	**93.31%**	**$ 6,632,598**	**24.01%**
Account	**Description**								
Other Distribution Expenses									
6105	Taxes Other Than Income Taxes	$ 371,935	$ 1,088,609	$ 1,603,355	$ 1,795,039	$ 706,430	64.89%	$ 191,684	11.96%
6215	Penalties	$ -	$ 30,000	$ 5,624	$ 31,212	$ 1,212	4.04%	$ 25,588	454.95%

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Appendix 2-J
OM&A Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2008 Barrie HYdro)	Last Board-approved Rebasing Year (2009 PowerStream South)	Most Current Actual Year (2011 MIFRS)	Test Year (2013)	Test Year Versus Last Rebasing (PowerStream South)		Test Year Versus Most Current Actuals	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
6225	Other Deductions	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Other distribution expenses		**$ 371,935**	**$ 1,118,609**	**$ 1,608,979**	**$ 1,826,251**				
Total OM&A		**$ 10,047,532**	**$ 43,216,300**	**$ 73,885,361**	**$ 85,701,101**	**$ 44,705,560**	**98.31%**	**$ 11,598,468**	**15.99%**

Note 1 The comparison between 2009 Board Approved and 2013 Test year is **not valid**, due to:
1. 2009 Board Approved amounts are for PowerStream South only; the 2013 test year is for PowerStream Combined
2. The overall increase in OM&A includes the increase due to the transition to IFRS
The IFRS impact amounts to $11,798,630.

Note 2 "Other Distribution expenses" are included in the analysis,as these amounts were part of Board Approved amounts and mainly include property taxes in account 6105

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Appendix 2-K
Employee Costs - Core Business

	2008	2009	2009	2010	2011	2012	2013 Test Year
	PS North	PS South	PowerStream Combined				
	LRY - Board Approved	LRY - Board Approved	Actual	Actual	Actual	Budget	Budget
Number of Employees (FTEs including Part-Time)							
Board	**5**	**10**	13	13	13	13	13
Executive	**4**	**18**	28	27	28	28	28
Management	**24**	**66**	80	83	76	86	89
Non-Union	**13**	**54**	44	48	49	54	61
Union	**77**	**263**	306	314	315	328	337
Temp & students		**23**	45	43	47	41	41
Total	**123**	**434**	**516**	**528**	**529**	**549**	**569**
Number of Part Time Employees (Headcount, included above)							
Executive							
Management			1.00	1.00	1.00	1.00	1.00
Non-Union	**5**						
Union			1.00	1.00	1.00	1.00	1.00
Total	**5**	**-**	2.00	2.00	2.00	2.00	2.00
Total Salary and Wages							
Board		**$ 300,770**	$ 265,148	$ 259,700	$ 286,350	$ 384,705	$ 396,247
Executive	**$ 525,030**	**$ 3,137,562**	$ 4,480,371	$ 4,506,488	$ 4,913,204	$ 4,901,404	$ 5,093,239
Management	**$ 2,079,739**	**$ 6,500,109**	$ 7,655,684	$ 8,095,730	$ 7,968,621	$ 9,191,456	$ 9,887,022
Non-Union	**$ 765,268**	**$ 3,357,381**	$ 3,562,110	$ 3,964,454	$ 4,348,556	$ 4,591,121	$ 5,466,397
Union	**$ 5,086,257**	**$ 16,937,753**	$ 19,965,669	$ 21,486,970	$ 22,111,996	$ 23,622,587	$ 25,130,245
Temp & students		**$-**	$ 1,645,620	$ 1,370,150	$ 1,456,837	$ 1,517,836	$ 1,563,826
Total	**$ 8,456,294**	**$ 30,233,575**	**$ 37,574,602**	**$ 39,683,492**	**$ 41,085,563**	**$ 44,209,109**	**$ 47,536,976**
Over Time							
Board							
Executive			$ -	$-			
Management			$ 189,874	$ 93,659	$ 95,670	$ 26,123	$ 26,903
Non-Union			$ 17,746	$ 12,729	$ 7,776		
Union		**$ 1,390,625**	$ 2,664,178	$ 3,591,481	$ 4,066,061	$ 2,516,721	$ 2,633,702
Temp & students			$ 6,525	$ 2,685	$ 6,254		
Total		**$ 1,390,625**	**$ 2,878,322**	**$ 3,700,553**	**$ 4,175,761**	**$ 2,542,844**	**$ 2,660,605**
Performance Incentive Plan							
Board				$-			
Executive	**$ 20,383**	**$ 593,447**		$ 1,026,341	$ 966,038	$ 956,380	$ 991,343
Management	**$ 71,026**	**$ 327,254**		$ 480,996	$ 528,233	$ 586,221	$ 629,699

	2008	2009	2009	2010	2011	2012	2013 Test Year
	PS North	PS South	PowerStream Combined				
	LRY - Board Approved	LRY - Board Approved	Actual	Actual	Actual	Budget	Budget
Non-Union	**$ 19,597**	**$ 121,400**		$ 257,126	$ 263,232	$ 229,556	$ 273,320
Union							$-
Temp & students							
Total	**$ 111,006**	**$ 1,042,102**	**$-**	**$ 1,764,463**	**$ 1,757,503**	**$ 1,772,157**	**$ 1,894,362**
Total Compensation (excluding Benefit) include Salary and Wages, Over Time, and Performance Incentive Plan							
Board	**$-**	**$ 300,770**	$ 265,148	$ 259,700	$ 286,350	$ 384,705	$ 396,247
Executive	**$ 545,413**	**$ 3,731,009**	$ 4,480,371	$ 5,532,829	$ 5,879,243	$ 5,857,784	$ 6,084,582
Management	**$ 2,150,765**	**$ 6,827,363**	$ 7,845,558	$ 8,670,384	$ 8,592,523	$ 9,803,800	$ 10,543,624
Non-Union	**$ 784,865**	**$ 3,478,781**	$ 3,579,856	$ 4,234,309	$ 4,619,563	$ 4,820,677	$ 5,739,716
Union	**$ 5,086,257**	**$ 18,328,377**	$ 22,629,846	$ 25,078,450	$ 26,178,057	$ 26,139,308	$ 27,763,948
Temp & students	**$-**	**$-**	$ 1,652,144	$ 1,372,835	$ 1,463,091	$ 1,517,836	$ 1,563,826
Total	**$ 8,567,300**	**$ 32,666,301**	**$ 40,452,924**	**$ 45,148,508**	**$ 47,018,828**	**$ 48,524,110**	**$ 52,091,943**
Current Benefits							
Board		**$ 20,060**	$ 18,280	$ 22,252	$ 19,528	$ 26,935	$ 27,743
Executive	**$ 100,618**	**$ 659,952**	$ 710,667	$ 924,613	$ 1,035,751	$ 1,166,620	$ 1,245,746
Management	**$ 473,215**	**$ 1,658,976**	$ 1,413,309	$ 1,848,058	$ 1,820,771	$ 2,549,599	$ 2,734,388
Non-Union	**$ 156,904**	**$ 1,016,160**	$ 728,090	$ 1,010,475	$ 1,125,461	$ 1,325,712	$ 1,593,891
Union	**$ 1,395,618**	**$ 5,810,813**	$ 4,829,857	$ 4,858,594	$ 5,346,045	$ 5,638,192	$ 6,151,908
Temp & students		**$-**	$ 157,025	$ 207,411	$ 154,536	$ 218,034	$ 222,154
Total	**$ 2,126,355**	**$ 9,165,961**	**$ 7,857,228**	**$ 8,871,402**	**$ 9,502,092**	**$ 10,925,092**	**$ 11,975,829**
Accrued Pension and Post-Retirement Benefits							
Board							
Executive							
Management	**$ 183,000**	**$ 1,080,000**	$ 453,312	$ 926,297	$ 591,133	$ 828,013	$ 852,854
Non-Union							
Union			$ 511,182	$ 1,044,547	$ 666,597	$ 933,717	$ 961,728
Temp & students							
Total	**$ 183,000**	**$ 1,080,000**	**$ 964,494**	**$ 1,970,844**	**$ 1,257,730**	**$ 1,761,730**	**$ 1,814,582**
Total Benefits (Current + Accrued)							
Board	**$-**	**$ 20,060**	$ 18,280	$ 22,252	$ 19,528	$ 26,935	$ 27,743
Executive	**$ 100,618**	**$ 659,952**	$ 710,667	$ 924,613	$ 1,035,751	$ 1,166,620	$ 1,245,746
Management	**$ 656,215**	**$ 2,738,976**	$ 1,866,621	$ 2,774,354	$ 2,411,904	$ 3,377,612	$ 3,587,241
Non-Union	**$ 156,904**	**$ 1,016,160**	$ 728,090	$ 1,010,475	$ 1,125,461	$ 1,325,712	$ 1,593,891
Union	**$ 1,395,618**	**$ 5,810,813**	$ 5,341,039	$ 5,903,141	$ 6,012,642	$ 6,571,909	$ 7,113,636
Temp & students	**$-**	**$-**	$ 157,025	$ 207,411	$ 154,536	$ 218,034	$ 222,154
Total	**$ 2,309,355**	**$ 10,245,961**	**$ 8,821,722**	**$ 10,842,246**	**$ 10,759,822**	**$ 12,686,822**	**$ 13,790,411**
Total Compensation including Benefits							
Board	**$-**	**$ 320,826**	$ 283,428	$ 281,952	$ 305,878	$ 411,640	$ 423,990
Executive	**$ 646,031**	**$ 4,390,958**	$ 5,191,038	$ 6,457,442	$ 6,914,994	$ 7,024,404	$ 7,330,328
Management	**$ 2,806,980**	**$ 8,486,313**	$ 9,712,179	$ 11,444,739	$ 11,004,428	$ 13,181,412	$ 14,130,866
Non-Union	**$ 941,769**	**$ 6,405,884**	$ 4,307,946	$ 5,244,785	$ 5,745,024	$ 6,146,389	$ 7,333,607
Union	**$ 6,481,875**	**$ 24,139,242**	$ 27,970,885	$ 30,981,592	$ 32,190,699	$ 32,711,217	$ 34,877,584
Temp & students	**$-**	**$-**	$ 1,809,169	$ 1,580,245	$ 1,617,627	$ 1,735,871	$ 1,785,980
Total	**$ 10,876,655**	**$ 43,743,223**	**$ 49,274,646**	**$ 55,990,754**	**$ 57,778,650**	**$ 61,210,932**	**$ 65,882,355**
Compensation - Average Yearly Base Wages							

	2008	2009	2009	2010	2011	2012	2013 Test Year
	PS North	PS South	PowerStream Combined				
	LRY - Board Approved	LRY - Board Approved	Actual	Actual	Actual	Budget	Budget
Board		$ 30,077	$ 20,396	$ 19,977	$ 22,027	$ 29,593	$ 30,481
Executive	$ 131,258	$ 174,309	$ 161,578	$ 163,889	$ 172,504	$ 173,809	$ 180,611
Management	$ 86,656	$ 98,487	$ 95,493	$ 97,868	$ 105,054	$ 106,877	$ 111,090
Non-Union	$ 58,867	$ 62,059	$ 81,868	$ 83,457	$ 88,191	$ 85,815	$ 89,613
Union	$ 66,055	$ 64,500	$ 65,314	$ 68,383	$ 70,088	$ 72,108	$ 74,548
Temp & students			$ 36,189	$ 32,180	$ 31,047	$ 37,165	$ 37,985
Total	**$ 71,663**	**$ 69,711**	**$ 72,880**	**$ 75,227**	**$ 77,658**	**$ 80,506**	**$ 83,476**
Compensation - Average Yearly Overtime							
Board			$-	$-	$-	$-	$-
Executive			$ -	$-	$-	$-	$-
Management			$ 2,368	$ 1,132	$ 1,261	$ 304	$ 302
Non-Union			$ 408	$ 268	$ 158	$-	$-
Union		5,296	$ 8,715	$ 11,430	$ 12,888	$ 7,682	$ 7,813
Temp & students			$ 143	$ 63	$ 133	$-	$-
Total			**$ 5,583**	**$ 7,015**	**$ 7,893**	**$ 4,631**	**$ 4,672**
Compensation - Average Yearly Incentive Pay							
Board			$-	$-	$-	$-	$-
Executive	$ 5,096	32,969	$-	$ 37,325	$ 33,918	$ 33,914	$ 35,154
Management	$ 2,959	4,958	$-	$ 5,815	$ 6,964	$ 6,817	$ 7,075
Non-Union	$ 1,507	2,244	$-	$ 5,413	$ 5,338	$ 4,291	$ 4,481
Union		-	$-	$-	$-	$-	$-
Temp & students			$-	$-	$-	$-	$-
Total	**$ 2,707**	**$ 2,402.82**	**$-**	**$ 3,345**	**$ 3,322**	**$ 3,227**	**$ 3,327**
Compensation - Average Yearly Benefits							
Board	-	$ 2,006	$ 1,406	$ 1,712	$ 1,502	$ 2,072	$ 2,134
Executive	25,155	$ 36,664	$ 25,629	$ 33,626	$ 36,366	$ 41,370	$ 44,175
Management	19,717	$ 25,136	$ 17,629	$ 22,341	$ 24,004	$ 29,647	$ 30,723
Non-Union	12,070	$ 18,783	$ 16,734	$ 21,272	$ 22,825	$ 24,780	$ 26,129
Union	18,125	$ 22,128	$ 15,800	$ 15,463	$ 16,945	$ 17,211	$ 18,250
Temp & students		$-	$ 3,453	$ 4,871	$ 3,293	$ 5,339	$ 5,396
Total	**18,020**	**$ 21,134**	**$ 15,240**	**$ 16,817**	**$ 17,961**	**$ 19,895**	**$ 21,030**
Total Compensation	**$ 10,876,655**	**$ 43,743,223**	**$ 49,274,646**	**$ 55,990,754**	**$ 57,778,650**	**$ 61,210,932**	**$ 65,882,355**
Total Compensation Charged to OM&A *	**$ 4,641,106**	**$ 24,721,325**	**$ 31,558,670**	**$ 29,223,226**	**$ 29,511,565**	**$ 42,774,921**	**$ 46,262,698**
Total Compensation Capitalized	**$ 6,235,549**	**$ 19,021,898**	**$ 17,715,976**	**$ 26,767,528**	**$ 28,267,085**	**$ 18,436,011**	**$ 19,619,657**
% in OMA	**43%**	**57%**	**64%**	**52%**	**51%**	**70%**	**70%**

***Notes: In 2009 PS south rate EDR model, total compensation charged to OM&A had not been filed in the compensation table.**

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Cost of Capital / Capitalization Ratio

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2009 Approved (PowerStream South)					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.0%		$325,249	5.89%	$19,166
2	Short-term Debt	4.0%	(1)	$23,232	1.33%	$309
3	**Total Debt**	60.0%		$348,481	5.59%	$19,475
	Equity					
4	Common Equity	40.0%		$232,321	8.01%	$18,609
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	40.0%		$232,321	8.01%	$18,609
7	**Total**	100.0%		$580,802	6.56%	$38,084

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2009 Actual (PowerStream Combined)					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	53.7%		$357,430	6.06%	$21,666
2	Short-term Debt	6.0%	(1)	$40,000	1.33%	$532
3	**Total Debt**	59.7%		$397,430	5.59%	$22,198
	Equity					
4	Common Equity	40.3%		$268,248	8.01%	$21,487
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	40.3%		$268,248	8.01%	$21,487
7	**Total**	100.0%		$665,678	6.56%	$43,685
				-		

Line No.	Particulars	Capitalization Ratio	Cost Rate	Return

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Cost of Capital / Capitalization Ratio

2010 Actual (PowerStream Combined)

		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	52.3%		$357,430	6.01%	$21,482
2	Short-term Debt	5.9%	(1)	$40,000	2.07%	$828
3	**Total Debt**	58.2%		$397,430	5.61%	$22,310
	Equity					
4	Common Equity	41.8%		$285,429	9.85%	$28,115
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	41.8%		$285,429	9.85%	$28,115
7	**Total**	100.0%		$682,859	7.38%	$50,425
				-		

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return

2011 Actual (PowerStream Combined)

		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	51.0%		$357,430	6.01%	$21,482
2	Short-term Debt	5.7%	(1)	$40,000	2.46%	$984
3	**Total Debt**	56.7%		$397,430	5.65%	$22,466
	Equity					
4	Common Equity	43.3%		$303,746	9.58%	$29,099
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	43.3%		$303,746	9.58%	$29,099
7	**Total**	100.0%		$701,176	7.35%	$51,565
				-		

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return

2012 Bridge Year (PowerStream Combined)

		(%)		($)	(%)	($)

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Cost of Capital / Capitalization Ratio

	Debt					
1	Long-term Debt	54.8%		$407,430	5.02%	$20,437
2	Short-term Debt	3.4%	(1)	$25,000	2.08%	$520
3	**Total Debt**	58.2%		$432,430	4.85%	$20,957
	Equity					
4	Common Equity	41.8%		$310,535	9.12%	$28,321
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	41.8%		$310,535	9.12%	$28,321
7	**Total**	100.0%		$742,965	6.63%	$49,278
				-		

2013 Test Year (PowerStream Combined)

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.0%		$452,430	4.96%	$22,422
2	Short-term Debt	3.1%	(1)	$25,000	2.08%	$520
3	**Total Debt**	59.1%		$477,430	4.81%	$22,942
	Equity					
4	Common Equity	40.9%		$330,619	9.12%	$30,152
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	40.9%		$330,619	9.12%	$30,152
7	**Total**	100.0%		$808,049	6.57%	$53,094
				-		

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Appendix 2-O
Cost Allocation

Please complete the following four tables.

a) **Allocated Costs**

Classes	**Costs Allocated from Previous Study (PowerStream 2009)**	**%**	**Costs Allocated in Test Year (2013) Study (Column 7A)**	**%**
Residential	$ 66,551,755	54.94%	$ 95,291,157	53.37%
GS < 50 kW	$ 16,174,114	13.35%	$ 27,734,368	15.53%
GS > 50 kW	$ 36,202,283	29.89%	$ 52,348,687	29.32%
Large User	$ 54,552	0.05%	$ 376,565	0.21%
Street Lighting	$ 1,690,275	1.40%	$ 2,271,860	1.27%
Sentinel Lighting	$ 26,725	0.02%	$ 18,117	0.01%
Unmetered Scattered Load (USL)	$ 431,330	0.36%	$ 509,050	0.29%
Total	$ 121,131,034	100.00%	$ 178,549,804	100.00%

Notes

Customer Classification

Host Distributors: Provide information on embedded distributor(s) as a separate class, even if your proposal is to bill the embedded distributor(s) as (a) General Service customer(s).

If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

Class Revenue Requirements
If using the Board-issued model, enter data from Worksheet O-1, row **40** in the 2012 model.

For the Embedded Distributor(s), the Service Revenue Requirement does not include Account 4750 - Low Voltage (LV) Costs

Exclude costs in deferral and variance accounts.

Include Smart Meter costs only to the extent that they are being included in Rate Base and Revenue Requirement (i.e. being transferred from accounts 1555 and 1556 as a result of a prudence review).

b) **Calculated Class Revenues**

Classes (same as previous table)	**Column 7B** **Load Forecast (LF) X current approved rates**	**Column 7C** **LF X current approved rates X (1 + d)**	**Column 7D** **LF X proposed rates**	**Column 7E** **Miscellaneous Revenue**
Residential	$ 83,376,466	$ 91,268,313	$ 91,268,313	$ 5,123,849
GS < 50 kW	$ 23,761,948	$ 26,011,092	$ 26,011,092	$ 1,397,719
GS > 50 kW	$ 44,733,723	$ 48,967,911	$ 48,967,911	$ 2,392,812
Large User	$ 136,436	$ 149,350	$ 369,350	$ 7,830
Street Lighting	$ 2,376,080	$ 2,600,983	$ 2,380,983	$ 100,858
Sentinel Lighting	$ 14,528	$ 15,904	$ 15,904	$ 839
Unmetered Scattered Load (USL)	$ 433,243	$ 474,251	$ 474,251	$ 38,094
Total	$ 154,832,425	$ 169,487,804	$ 169,487,804	$ 9,062,000.00
	line 18	*line 23*	*As per Rate model*	*line 19*

Notes:

Columns 7B to 7D

LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, **and** kWh or kW, as applicable)

Exclude revenue from rate adders and rate riders. For Embedded Distributor(s): exclude revenue in account 4075.

Columns 7C and 7D:

Column total in each column should equal the Base Revenue Requirement.

For Embedded Distributor(s), Base Revenue Requirement does not include Account 4750 - Low Voltage Costs

Column 7C:

The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

Column 7E:

If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

c) Rebalancing Revenue-to-Cost (R/C) Ratios

	Previously Approved Ratios		**Status Quo Ratios**	**Proposed Ratios**	**Policy Range**
	PowerStream North	**PowerStream South**	**(7C + 7E) / (7A)**	**(7D + 7E) / (7A)**	
Class	**2011***	**2009**			
	%	%	%	%	%
Residential	111.9	92.9	101.2	101.2	85 - 115
GS < 50 kW	100.0	116.7	98.8	98.8	80 - 120
GS > 50 kW	81.0	106.5	98.1	98.1	80 - 120
Large User	86.0	115.0	41.7	100.2	85 - 115
Street Lighting	70.0	74.5	118.9	109.2	70 - 120
Sentinel Lighting		75.4	92.4	92.4	80 - 120
Unmetered Scattered Load (USL)	99.0	119.9	100.6	100.6	80 - 120

Notes:

Previously Approved Revenue-to-Cost Ratios

For PowerStream North, the Ratios approved in 2008 Rate Application were adjusted during 3 years fo IRM period for Street Lighting class

For applicants that have had rates adjusted only under IRM 2, the Most Recent Year is 2006, and the applicant should enter the ratios from their Informational Filing.

Status Quo Ratios

The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1.

Status Quo means "No Rebalancing" or "Before Rebalancing".

d) Proposed Revenue-to-Cost Ratios

Class	**Proposed Revenue-to-Cost Ratios**			**Policy Range**
	2012	**2013**	**2014**	
	%	%	%	%
Residential	101.16			85 - 115
GS < 50 kW	98.83			80 - 120
GS > 50 kW	98.11			80 - 120
Large User	100.16			85 - 115
Street Lighting	109.24			70 - 120
Sentinel Lighting	92.41			80 - 120
Unmetered Scattered Load (USL)	100.65			80 - 120

The applicant should complete Table (d) if it is applying for approval of a revenue to cost ratio in 2012 that is outside the Board’s policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2012 Table (d), enter the planned ratios for the classes that will be ‘Change’ and ‘No Change’ in 2013 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 ‘Decision – Cost Revenue Adjustment’, column d), and enter TBD for class(es) that will be entered as ‘Rebalance’.

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Appendix 2-P
Loss Factors

		Historical Years			**3-Year Average**
		2009	**2010**	**2011**	
	Losses Within Distributor's System				
A(1)	"Wholesale" kWh delivered to distributor (higher value)	Not available	Not available	Not available	0
A(2)	"Wholesale" kWh delivered to distributor (lower value)	8,238,568,148	8,611,402,381	8,658,416,020	8,502,795,516
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	27,205,480	27,609,737	27,116,405	27,310,541
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	8,211,362,668	8,583,792,644	8,631,299,615	8,475,484,976
D	"Retail" kWh delivered by distributor	8,039,883,040	8,334,777,460	8,394,821,657	8,256,494,052
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	27,205,480	27,609,737	27,116,405	27,310,541
F	Net "Retail" kWh delivered by distributor = **D - E**	8,012,677,560	8,307,167,723	8,367,705,252	8,229,183,512
G	Loss Factor in Distributor's system = **C / F**	1.0248	1.0333	1.0315	1.0299
	Losses Upstream of Distributor's				
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045
	Total Losses				
I	Total Loss Factor = **G x H**	1.0294	1.0379	1.0361	1.0345

Notes

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the <u>higher</u> of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the <u>higher</u> of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the <u>lower</u> of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to an actual or virtual meter at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the <u>lower</u> of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to **D** should equal "total billed energy sales in kWhs for each rate class" in item 1 of Section 2.1.3 of the "Electricity Reporting and Record-keeping Requirements" dated May 1, 2010 or in any successor document.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

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Appendix 2-U
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	305,233	311,385	308,309	2,727,901,711		$ 13.57	$ 0.0154		$ 92,214,724	$ 92,190,288		$ 92,190,288	-$ 24,436
GS < 50 kW	Customers	30,966	31,432	31,199	1,049,877,268		$ 27.91	$ 0.0151		$ 26,302,316	$ 26,328,439		$ 26,328,439	$ 26,123
GS > 50 to 4,999 kW	Customers	4,647	4,676	4,662		12,130,724	$ 148.18		$ 3.6640	$ 52,735,867	$ 50,412,289	$ 2,322,897	$ 52,735,186	-$ 680
Large Use	Customers	2	2	2		187,932	$ 6,017.47		$ 1.9408	$ 509,158	$ 396,400	$ 112,759	$ 509,159	$ 1
Streetlighting	Connections	82,656	84,084	83,370		176,787	$ 1.34		$ 5.9768	$ 2,397,212	$ 2,397,217		$ 2,397,217	$ 5
Sentinel Lighting	Connections	120	120	120		1,240	$ 3.51		$ 8.8506	$ 16,032	$ 16,032		$ 16,032	-$ 0
Unmetered Scattered Load	Connections	2,804	2,824	2,814	12,918,549		$ 8.06	$ 0.0159		$ 477,575	$ 478,595		$ 478,595	$ 1,020
				-						$ -			$ -	$ -
Total										$ 174,652,883	$ 172,219,260	$ 2,435,656	$ 174,654,916	$ 2,033

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Residential**

Consumption **800** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 11.99	1	$ 11.99	$ 13.57	1	$ 13.57	$ 1.58	13.18%
Smart Meter Rate Adder	monthly	$ 1.28	1	$ 1.28	$ -	1	$ -	-$ 1.28	-100.00%
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ 0.1400	1	$ 0.14	$ -	1	$ -	-$ 0.14	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0135	800	$ 10.80	$ 0.0151	800	$ 12.08	$ 1.28	11.85%
Low Voltage Rate Adder	per kWh	$ 0.0001	800	$ 0.08	$ 0.0003	800	$ 0.24	$ 0.16	200.00%
Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Volumetric Rate Rider(s)	per kWh	-$ 0.0004	800	-$ 0.32	$ -	800	$ -	$ 0.32	-100.00%
Smart Meter Disposition Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
		$ -		$ -	$ -		$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 23.97**			**$ 26.09**	**$ 2.12**	**8.84%**
RTSR - Network	per kWh	$ 0.0073	824	$ 6.01	$ 0.0071	828	$ 5.88	-$ 0.14	-2.31%
RTSR - Line and Transformation Connection	per kWh	$ 0.0027	824	$ 2.22	$ 0.0032	828	$ 2.65	$ 0.42	19.05%
Sub-Total B - Delivery (including Sub-Total A)				**$ 32.21**			**$ 34.61**	**$ 2.41**	**7.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	824	$ 4.28	$ 0.0052	828	$ 4.30	$ 0.02	0.45%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	824	$ 0.91	$ 0.0011	828	$ 0.91	$ 0.00	0.45%
Special Purpose Charge	per kWh	$ -	824	$ -	$ -	828	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	0.00%
Energy Tier 2	per kWh	$ 0.0880	74	$ 6.50	$ 0.0880	78	$ 6.83	$ 0.32	4.98%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 106.00**			**$ 108.76**	**$ 2.75**	**2.60%**
HST		13%		$ 13.78	13%		$ 14.14	$ 0.36	2.60%
Total Bill (including Sub-total B)				**$ 119.79**			**$ 122.90**	**$ 3.11**	**2.60%**
OCEB				-$ 11.98			-$ 12.29	-$ 0.31	2.59%
Total Bill (including OCEB)				**$ 107.81**			**$ 110.61**	**$ 2.80**	**2.60%**
Loss Factor (%)		2.99%			3.45%				
Threshold		750			750				

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **General Service Less Than 50 kW**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 28.64	1	$ 28.64	$ 27.91	1	$ 27.91	-$ 0.73	-2.55%
Smart Meter Rate Adder	monthly	$ 1.0100	1	$ 1.01	$ -	1	$ -	-$ 1.01	-100.00%
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ 3.3700	1	$ 3.37	$ -	1	$ -	-$ 3.37	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0116	2,000	$ 23.20	$ 0.0148	2,000	$ 29.60	$ 6.40	27.59%
Low Voltage Rate Adder	per kWh	$ 0.0001	2,000	$ 0.20	$ 0.0003	2,000	$ 0.60	$ 0.40	200.00%
Volumetric Rate Adder(s)	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Volumetric Rate Rider(s)	per kWh	-$ 0.0003	2,000	-$ 0.60	$ -	2,000	$ -	$ 0.60	-100.00%
Smart Meter Disposition Rider	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	2,000	$ -	-$ 0.0012	2,000	-$ 2.40	-$ 2.40	
		$ -		$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 55.82**			**$ 55.91**	**$ 0.09**	**0.16%**
RTSR - Network	per kWh	$ 0.0066	2,060	$ 13.59	$ 0.0065	2,069	$ 13.45	-$ 0.15	-1.08%
RTSR - Line and Transformation Connection	per kWh	$ 0.0024	2,060	$ 4.94	$ 0.0028	2,069	$ 5.79	$ 0.85	17.19%
Sub-Total B - Delivery (including Sub-Total A)				**$ 74.36**			**$ 75.15**	**$ 0.79**	**1.07%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,060	$ 10.71	$ 0.0052	2,069	$ 10.76	$ 0.05	0.45%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,060	$ 2.27	$ 0.0011	2,069	$ 2.28	$ 0.01	0.45%
Special Purpose Charge	per kWh	$ -	2,060	$ -	$ -	2,069	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Energy	per kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	0.00%
		$ 0.0880	1,310	$ 115.26	$ 0.0880	1,319	$ 116.07	$ 0.81	0.70%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 273.10**			**$ 274.76**	**$ 1.66**	**0.61%**
HST		13%		$ 35.50	13%		$ 35.72	$ 0.22	0.61%
Total Bill (including Sub-total B)				**$ 308.60**			**$ 310.48**	**$ 1.88**	**0.61%**
OCEB				-$ 30.86			-$ 31.05	-$ 0.19	0.62%
Total Bill (including OCEB)				**$ 277.74**			**$ 279.43**	**$ 1.69**	**0.61%**
Loss Factor (%)		2.99%			3.45%				
Threshold		750			750				

Notes:

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **General Service Greater Than 50 kW**

Consumption **80,000** **kWh**
Load **250** **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 84.45	1	$ 84.45	$ 148.18	1	$ 148.18	$ 63.73	75.46%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.5036	250	$ 875.90	$ 3.5449	250	$ 886.23	$ 10.33	1.18%
Low Voltage Rate Adder	per kW	$ 0.0472	250	$ 11.80	$ 0.1191	250	$ 29.78	$ 17.98	152.33%
Volumetric Rate Adder(s)	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.0501	250	-$ 12.53	$ -	250	$ -	$ 12.53	-100.00%
Smart Meter Disposition Rider	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	250	$ -	-$ 0.5397	250	-$ 134.93	-$ 134.93	
GA Variance Account Disposition Rate Rider (Non-RPP)	per kWh	$ -	1	$ -	$ 0.0017	80,000	$ 136.00	$ 136.00	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 959.63**			**$ 1,065.46**	**$ 105.83**	**11.03%**
RTSR - Network	per kW	$ 2.6667	250	$ 666.68	$ 2.6030	250	$ 650.75	-$ 15.93	-2.39%
RTSR - Line and Transformation Connection	per kW	$ 0.9755	250	$ 243.88	$ 1.0984	250	$ 274.60	$ 30.73	12.60%
Sub-Total B - Delivery (including Sub-Total A)				**$ 1,870.18**			**$ 1,990.81**	**$ 120.63**	**6.45%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	82,392	$ 428.44	$ 0.0052	82,760	$ 430.35	$ 1.91	0.45%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	82,392	$ 90.63	$ 0.0011	82,760	$ 91.04	$ 0.40	0.45%
Special Purpose Charge	per kWh	$ -	82,392	$ -	$ -	82,760	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	80,000	$ 560.00	$ 0.0070	80,000	$ 560.00	$ -	0.00%
Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
Energy	per kWh	$ 0.0820	81,642	$ 6,694.64	$ 0.0820	82,010	$ 6,724.82	$ 30.18	0.45%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 9,705.64**			**$ 9,858.76**	**$ 153.12**	**1.58%**
HST		13%		$ 1,261.73	13%		$ 1,281.64	$ 19.91	1.58%
Total Bill (including Sub-total B)				**$ 10,967.37**			**$ 11,140.40**	**$ 173.03**	**1.58%**
Loss Factor (%)		2.99%			3.45%				
Threshold		750			750				

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Large Use**

Consumption 2,800,000 **kWh**
Load 7,350 **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 2,173.63	1	$ 2,173.63	$ 6,017.47	1	$ 6,017.47	$ 3,843.84	176.84%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.0484	7,350	$ 7,705.74	$ 1.7969	7,350	$ 13,207.22	$ 5,501.48	71.39%
Low Voltage Rate Adder	per kW	$ 0.0558	7,350	$ 410.13	$ 0.1439	7,350	$ 1,057.67	$ 647.54	157.89%
Volumetric Rate Adder(s)	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.0175	7,350	-$ 128.63	$ -	7,350	$ -	$ 128.63	-100.00%
Smart Meter Disposition Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	7,350	$ -	-$ 0.1895	7,350	-$ 1,392.83	-$ 1,392.83	
GA Variance Account Disposition Rate Rider (Non-RPP)	per kWh			$ -	$ 0.0017	2,800,000	$ 4,760.00	$ 4,760.00	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 10,160.88**			**$ 23,649.73**	**$ 13,488.85**	**132.75%**
RTSR - Network	per kW	$ 3.1285	7,350	$ 22,994.48	$ 3.0886	7,350	$ 22,701.21	-$ 293.26	-1.28%
RTSR - Line and Transformation Connection	per kW	$ 1.1529	7,350	$ 8,473.82	$ 1.1266	7,350	$ 8,280.51	-$ 193.31	-2.28%
Sub-Total B - Delivery (including Sub-Total A)				**$ 41,629.17**			**$ 54,631.45**	**$ 13,002.28**	**31.23%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,840,600	$ 14,771.12	$ 0.0052	2,840,600	$ 14,771.12	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,840,600	$ 3,124.66	$ 0.0011	2,840,600	$ 3,124.66	$ -	0.00%
Special Purpose Charge	per kWh	$ -	2,840,600	$ -	$ -	2,840,600	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,800,000	$ 19,600.00	$ 0.0070	2,800,000	$ 19,600.00	$ -	0.00%
Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
Energy	per kWh	$ 0.0820	2,839,850	$ 232,867.70	$ 0.0820	2,839,850	$ 232,867.70	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 312,054.40**			**$ 325,056.68**	**$ 13,002.28**	**4.17%**
HST		13%		$ 40,567.07	13%		$ 42,257.37	$ 1,690.30	4.17%
Total Bill (including Sub-total B)				**$ 352,621.47**			**$ 367,314.04**	**$ 14,692.57**	**4.17%**

Loss Factor (%)	1.45%	1.45%
Threshold	750	750

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Unmetered Scattered Load**

Consumption 150 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 14.32	1	$ 14.32	$ 8.06	1	$ 8.06	-$ 6.26	-43.72%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0087	150	$ 1.31	$ 0.0156	150	$ 2.34	$ 1.04	79.31%
Low Voltage Rate Adder	per kWh	$ 0.0001	150	$ 0.02	$ 0.0003	150	$ 0.05	$ 0.03	200.00%
Volumetric Rate Adder(s)	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Volumetric Rate Rider(s)	per kWh	-$ 0.0007	150	-$ 0.11	$ -	150	$ -	$ 0.11	-100.00%
Smart Meter Disposition Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh	$ -	150	$ -	-$ 0.0022	150	-$ 0.33	-$ 0.33	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 15.54**			**$ 10.32**	**-$ 5.22**	**-33.60%**
RTSR - Network	per kWh	$ 0.0066	154	$ 1.02	$ 0.0064	155	$ 0.99	-$ 0.03	-2.60%
RTSR - Line and Transformation Connection	per kWh	$ 0.0027	154	$ 0.42	$ 0.0031	155	$ 0.48	$ 0.06	15.33%
Sub-Total B - Delivery (including Sub-Total A)				**$ 16.97**			**$ 11.79**	**-$ 5.18**	**-30.54%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	154	$ 0.80	$ 0.0052	155	$ 0.81	$ 0.00	0.45%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	154	$ 0.17	$ 0.0011	155	$ 0.17	$ 0.00	0.45%
Special Purpose Charge	per kWh	$ -	154	$ -	$ -	155	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	154	$ 11.59	$ 0.0750	155	$ 11.64	$ 0.05	0.45%
Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 30.83**			**$ 25.70**	**-$ 5.13**	**-16.63%**
HST		13%		$ 4.01	13%		$ 3.34	-$ 0.67	-16.63%
Total Bill (including Sub-total B)				**$ 34.84**			**$ 29.05**	**-$ 5.79**	**-16.62%**
Loss Factor (%)		2.99%			3.45%				
Threshold		750			750				

Notes:

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Sentinel**

Consumption 180 **kWh**
Load 1.0 **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 2.00	1	$ 2.00	$ 3.51	1	$ 3.51	$ 1.51	75.50%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 9.3917	1.0	$ 9.39	$ 8.7473	1.0	$ 8.75	-$ 0.64	-6.86%
Low Voltage Rate Adder	per kW	$ 0.0401	1.0	$ 0.04	$ 0.1033	1.0	$ 0.10	$ 0.06	157.61%
Volumetric Rate Adder(s)	per kW	$ -	1.0	$ -	$ -	1.0	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.1458	1.0	-$ 0.15	$ -	1.0	$ -	$ 0.15	-100.00%
Smart Meter Disposition Rider	per kW	$ -	1.0	$ -	$ -	1.0	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	1.0	$ -	$ -	1.0	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	1.0	$ -	-$ 0.7433	1.0	-$ 0.74	-$ 0.74	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 11.29**			**$ 11.82**	**$ 0.53**	**4.71%**
RTSR - Network	per kW	$ 2.0378	1.0	$ 2.04	$ 2.0118	1.0	$ 2.01	-$ 0.03	-1.28%
RTSR - Line and Transformation Connection	per kW	$ 0.8272	1.0	$ 0.83	$ 0.8084	1.0	$ 0.81	-$ 0.02	-2.27%
Sub-Total B - Delivery (including Sub-Total A)				**$ 14.15**			**$ 14.64**	**$ 0.49**	**3.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	185	$ 0.96	$ 0.0052	186	$ 0.97	$ 0.00	0.45%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	185	$ 0.20	$ 0.0011	186	$ 0.20	$ 0.00	0.45%
Special Purpose Charge	per kWh	$ -	185	$ -	$ -	186	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	180	$ 1.26	$ 0.0070	180	$ 1.26	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	185	$ 13.90	$ 0.0750	186	$ 13.97	$ 0.06	0.45%
Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 30.73**			**$ 31.29**	**$ 0.55**	**1.80%**
HST		13%		$ 4.00	13%		$ 4.07	$ 0.07	1.80%
Total Bill (including Sub-total B)				**$ 34.73**			**$ 35.35**	**$ 0.62**	**1.79%**
Loss Factor (%)		2.99%			3.45%				
Threshold		750			750				

Notes:

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PowerStream South

Bill Impacts - Monthly Consumptions

Customer Class: **Street Lighting**

Consumption **280** **kWh**
Load **1.00** **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 0.84	1	$ 0.84	$ 1.34	1	$ 1.34	$ 0.50	59.52%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Adder(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.8616	1.00	$ 4.86	$ 5.8850	1.00	$ 5.89	$ 1.02	21.05%
Low Voltage Rate Adder	per kW	$ 0.0367	1.00	$ 0.04	$ 0.0918	1.00	$ 0.09	$ 0.06	150.14%
Volumetric Rate Adder(s)	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.1276	1.00	-$ 0.13	$ -	1.00	$ -	$ 0.13	-100.00%
Smart Meter Disposition Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	$ -	1.00	$ -	-$ 0.6372	1.0	-$ 0.64	-$ 0.64	
GA Variance Account Disposition Rate Rider (Non-RPP)	per kW			$ -	$ 0.0017	1.0	$ 0.00	$ 0.00	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 5.61**			**$ 6.68**	**$ 1.07**	**19.08%**
RTSR - Network	per kW	$ 2.0174	1.00	$ 2.02	$ 1.9798	1.00	$ 1.98	-$ 0.04	-1.86%
RTSR - Line and Transformation Connection	per kW	$ 0.7584	1.00	$ 0.76	$ 0.8901	1.00	$ 0.89	$ 0.13	17.37%
Sub-Total B - Delivery (including Sub-Total A)				**$ 8.39**			**$ 9.55**	**$ 1.16**	**13.89%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	288.37	$ 1.50	$ 0.0052	290	$ 1.51	$ 0.01	0.45%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	288.37	$ 0.32	$ 0.0011	290	$ 0.32	$ 0.00	0.45%
Special Purpose Charge	per kWh	$ -	288.37	$ -	$ -	290	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	280	$ 1.96	$ 0.0070	280	$ 1.96	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	288	$ 21.63	$ 0.0750	290	$ 21.72	$ 0.10	0.45%
Energy Tier 2		$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 34.04**			**$ 35.31**	**$ 1.27**	**3.73%**
HST		13%		$ 4.43	13%		$ 4.59	$ 0.17	3.73%
Total Bill (including Sub-total B)				**$ 38.47**			**$ 39.90**	**$ 1.43**	**3.72%**

Loss Factor (%)	2.99%	3.45%
Threshold	800	800

Notes:

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PowerStream Barrie

Bill Impacts - Monthly Consumptions

monthly **Customer Class:** **Residential**

per kWh **Consumption** 800 **kWh**
per kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 15.34	1	$ 15.34	$ 13.57	1	$ 13.57	-$ 1.77	-11.54%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ 1.78	1	$ 1.78	$ -	1	$ -	-$ 1.78	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0137	800	$ 10.96	$ 0.0151	800	$ 12.08	$ 1.12	10.22%
Low Voltage Rate Adder	per kWh	$ 0.0008	800	$ 0.64	$ 0.0003	800	$ 0.24	-$ 0.40	-62.50%
Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
Volumetric Rate Rider(s)	per kWh	-$ 0.0006	800	-$ 0.48	$ -	800	$ -	$ 0.48	-100.00%
Smart Meter Disposition Rider	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
LRAM & SSM Rate Rider - effective until Apr 30, 2013	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kWh	-$ 0.0006	800	-$ 0.48	-$ 0.0006	800	-$ 0.48	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh			$ -	$ 0.0008	800	$ 0.64	$ 0.64	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 28.08**			**$ 26.57**	**-$ 1.51**	**-5.38%**
RTSR - Network	per kWh	$ 0.0069	845	$ 5.83	$ 0.0071	828	$ 5.88	$ 0.04	0.76%
RTSR - Line and Transformation Connection	per kWh	$ 0.0054	845	$ 4.56	$ 0.0032	828	$ 2.65	-$ 1.92	-41.97%
Sub-Total B - Delivery (including Sub-Total A)				**$ 38.48**			**$ 35.09**	**-$ 3.38**	**-8.79%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	845	$ 4.40	$ 0.0052	828	$ 4.30	-$ 0.09	-2.08%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	845	$ 0.93	$ 0.0011	828	$ 0.91	-$ 0.02	-2.08%
Special Purpose Charge	per kWh	$ -	845	$ -	$ -	828	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	800	$ 60.00	$ 0.0750	800	$ 60.00	$ -	0.00%
Energy Tier 2	per kWh	$ 0.0880	45	$ 3.98	$ 0.0880	28	$ 2.43	-$ 1.55	-38.94%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 113.63**			**$ 108.59**	**-$ 5.04**	**-4.44%**
HST		13%		$ 14.77	13%		$ 14.12	-$ 0.66	-4.44%
Total Bill (including Sub-total B)				**$ 128.40**			**$ 122.70**	**-$ 5.70**	**-4.44%**
OCEB				-$ 12.84			-$ 12.27	$ 0.57	-4.44%
Total Bill (including OCEB)				**$ 115.56**			**$ 110.43**	**-$ 5.13**	**-4.44%**
Loss Factor (%)		5.65%			3.45%				
Threshold		800			800				

Notes:

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PowerStream Barrie

Bill Impacts - Monthly Consumptions

monthly
per kWh
per kW

Customer Class: **General Service Less Than 50 kW**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 16.11	1	$ 16.11	$ 27.91	1	$ 27.91	$ 11.80	73.25%
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Adder(s)	monthly	$ 4.7300	1	$ 4.73	$ -	1	$ -	-$ 4.73	-100.00%
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0164	2,000	$ 32.80	$ 0.0148	2,000	$ 29.60	-$ 3.20	-9.76%
Low Voltage Rate Adder	per kWh	$ 0.0007	2,000	$ 1.40	$ 0.0003	2,000	$ 0.60	-$ 0.80	-57.14%
Volumetric Rate Adder(s)	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Volumetric Rate Rider(s)	per kWh	-$ 0.0004	2,000	-$ 0.80	$ -	2,000	$ -	$ 0.80	-100.00%
Smart Meter Disposition Rider	per kWh	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
LRAM & SSM Rate Rider - effective until Apr 30, 2013	per kWh	$ 0.0007	2,000	$ 1.40	$ 0.0007	2,000	$ 1.40	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kWh	-$ 0.0004	2,000	-$ 0.80	-$ 0.0004	2,000	-$ 0.80	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh		2,000	$ -	-$ 0.0009	2,000	-$ 1.80	-$ 1.80	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 54.84**			**$ 57.11**	**$ 2.27**	**4.14%**
RTSR - Network	per kWh	$ 0.0063	2,113	$ 13.31	$ 0.0065	2,069	$ 13.45	$ 0.14	1.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	2,113	$ 10.14	$ 0.0028	2,069	$ 5.79	-$ 4.35	-42.88%
Sub-Total B - Delivery (including Sub-Total A)				**$ 78.29**			**$ 76.35**	**-$ 1.94**	**-2.48%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,113	$ 10.99	$ 0.0052	2,069	$ 10.76	-$ 0.23	-2.08%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,113	$ 2.32	$ 0.0011	2,069	$ 2.28	-$ 0.05	-2.08%
Special Purpose Charge	per kWh	$ -	2,113	$ -	$ -	2,069	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,000	$ 14.00	$ 0.0070	2,000	$ 14.00	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	750	$ 56.25	$ 0.0750	750	$ 56.25	$ -	0.00%
Energy Tier 2	per kWh	$ 0.0880	1,363	$ 119.94	$ 0.0880	1,319	$ 116.07	-$ 3.87	-3.23%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 282.05**			**$ 275.96**	**-$ 6.09**	**-2.16%**
HST		13%		$ 36.67	13%		$ 35.87	-$ 0.79	-2.16%
Total Bill (including Sub-total B)				**$ 318.72**			**$ 311.83**	**-$ 6.89**	**-2.16%**
OCEB				-$ 31.87			-$ 31.18	$ 0.69	-2.17%
Total Bill (including OCEB)				**$ 286.85**			**$ 280.65**	**-$ 6.20**	**-2.16%**

	Current	Proposed
Loss Factor (%)	5.65%	3.45%
Threshold	750	750

Notes:

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PowerStream Barrie

Bill Impacts - Monthly Consumptions

monthly **Customer Class:** **General Service Greater Than 50 kW**

per kWh **Consumption** **80,000** **kWh**
per kW **Load** **250** **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 395.68	1	$ 395.68	$ 148.18	1	$ 148.18	-$ 247.50	-62.55%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.8393	250	$ 459.83	$ 3.5449	250	$ 886.23	$ 426.40	92.73%
Low Voltage Rate Adder	per kW	$ 0.2913	250	$ 72.83	$ 0.1191	250	$ 29.78	-$ 43.05	-59.11%
Volumetric Rate Adder(s)	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.0650	250	-$ 16.25	$ -	250	$ -	$ 16.25	-100.00%
Smart Meter Disposition Rider	per kW	$ -	250	$ -	$ -	250	$ -	$ -	
LRAM & SSM Rate Rider - effective until Apr 30, 2013	per kW	$ 0.0012	250	$ 0.30	$ 0.0012	250	$ 0.30	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kW	-$ 0.0705	250	-$ 17.63	-$ 0.0705	250	-$ 17.63	$ -	0.00%
GA Variance Account Disposition Rate Rider (Non-RPP)	per kW		250	$ -	$ 0.0030	80,000	$ 240.00	$ 240.00	
Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh			$ -	-$ 0.5536	250	-$ 138.40	-$ 138.40	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 894.76**			**$ 1,148.66**	**$ 253.90**	**28.38%**
RTSR - Network	per kW	$ 2.4796	250	$ 619.90	$ 2.6030	250	$ 650.75	$ 30.85	4.98%
RTSR - Line and Transformation Connection	per kW	$ 1.8993	250	$ 474.83	$ 1.0984	250	$ 274.60	-$ 200.23	-42.17%
Sub-Total B - Delivery (including Sub-Total A)				**$ 1,989.48**			**$ 2,074.01**	**$ 84.53**	**4.25%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	84,520	$ 439.50	$ 0.0052	82,760	$ 430.35	-$ 9.15	-2.08%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	84,520	$ 92.97	$ 0.0011	82,760	$ 91.04	-$ 1.94	-2.08%
Special Purpose Charge	per kWh	$ -	84,520	$ -	$ -	82,760	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	80,000	$ 560.00	$ 0.0070	80,000	$ 560.00	$ -	0.00%
Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
Energy	per kWh	$ 0.0820	83,770	$ 6,869.14	$ 0.0820	82,010	$ 6,724.82	-$ 144.32	-2.10%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 10,012.85**			**$ 9,941.96**	**-$ 70.88**	**-0.71%**
HST		13%		$ 1,301.67	13%		$ 1,292.46	-$ 9.21	-0.71%
Total Bill (including Sub-total B)				**$ 11,314.52**			**$ 11,234.42**	**-$ 80.10**	**-0.71%**

	Current Board-Approved	Proposed
Loss Factor (%)	5.65%	3.45%
Threshold	750	750

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

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PowerStream Barrie

Bill Impacts - Monthly Consumptions

monthly **Customer Class:** **Large Use**

per kWh	**Consumption**	**2,800,000**	**kWh**
per kW	**Load**	**7,350**	**kW**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 9,690.24	1	$ 9,690.24	$ 6,017.47	1	$ 6,017.47	-$ 3,672.77	-37.90%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 0.5918	7,350	$ 4,349.73	$ 1.7969	7,350	$ 13,207.22	$ 8,857.49	203.63%
Low Voltage Rate Adder	per kW	$ 0.3886	7,350	$ 2,856.21	$ 0.1439	7,350	$ 1,057.67	-$ 1,798.55	-62.97%
Volumetric Rate Adder(s)	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.0764	7,350	-$ 561.54	$ -	7,350	$ -	$ 561.54	-100.00%
Smart Meter Disposition Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	7,350	$ -	$ -	7,350	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kW	$ -	7,350	$ -	-$ 0.0829	7,350	-$ 609.32	-$ 609.32	
GA Variance Account Disposition Rate Rider (Non-RPP)	per kWh			$ -	$ 0.0001	2,800,000	$ 280.00	$ 280.00	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 16,334.64**			**$ 19,953.24**	**$ 3,618.60**	**22.15%**
RTSR - Network	per kW	$ 3.1192	7,350	$ 22,926.12	$ 3.0886	7,350	$ 22,701.21	-$ 224.91	-0.98%
RTSR - Line and Transformation Connection	per kW	$ 2.5775	7,350	$ 18,944.63	$ 1.1266	7,350	$ 8,280.51	-$ 10,664.12	-56.29%
Sub-Total B - Delivery (including Sub-Total A)				**$ 58,205.39**			**$ 50,934.96**	**-$ 7,270.43**	**-12.49%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2,840,600	$ 14,771.12	$ 0.0052	2,840,600	$ 14,771.12	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2,840,600	$ 3,124.66	$ 0.0011	2,840,600	$ 3,124.66	$ -	0.00%
Special Purpose Charge	per kWh	$ -	2,840,600	$ -	$ -	2,840,600	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2,800,000	$ 19,600.00	$ 0.0070	2,800,000	$ 19,600.00	$ -	0.00%
Energy	per kWh	$ 0.0820	750	$ 61.50	$ 0.0820	750	$ 61.50	$ -	0.00%
Energy	per kWh	$ 0.0820	2,839,850	$ 232,867.70	$ 0.0820	2,839,850	$ 232,867.70	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 328,630.62**			**$ 321,360.19**	**-$ 7,270.43**	**-2.21%**
HST		13%		$ 42,721.98	13%		$ 41,776.82	-$ 945.16	-2.21%
Total Bill (including Sub-total B)				**$ 371,352.59**			**$ 363,137.01**	**-$ 8,215.58**	**-2.21%**
Loss Factor (%)		1.45%			1.45%				
Threshold		750			750				

Notes:

For the Bill impact calculation purposes, the energy price is assumed to be the average of current tier prices

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PowerStream Barrie

Bill Impacts - Monthly Consumptions

monthly **Customer Class:** Unmetered Scattered Load

per kWh **Consumption** 150 kWh
per kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	monthly	$ 7.95	1	$ 7.95	$ 8.06	1	$ 8.06	$ 0.11	1.38%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
GEA funding rate adder	monthly	$ -	1	$ -	$ 0.20	1	$ 0.20	$ 0.20	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0161	150	$ 2.42	$ 0.0156	150	$ 2.34	-$ 0.08	-3.11%
Low Voltage Rate Adder	per kWh	$ 0.0007	150	$ 0.11	$ 0.0003	150	$ 0.05	-$ 0.06	-57.14%
Volumetric Rate Adder(s)	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Volumetric Rate Rider(s)	per kWh	-$ 0.0005	150	-$ 0.08	$ -	150	$ -	$ 0.08	-100.00%
Smart Meter Disposition Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	150	$ -	$ -	150	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kWh	-$ 0.0009	150	-$ 0.14	-$ 0.0009	150	-$ 0.14	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kWh			$ -	-$ 0.0014	150	-$ 0.21	-$ 0.21	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 10.26**			**$ 10.30**	**$ 0.04**	**0.39%**
RTSR - Network	per kWh	$ 0.0063	158	$ 1.00	$ 0.0064	155	$ 0.99	-$ 0.01	-0.53%
RTSR - Line and Transformation Connection	per kWh	$ 0.0048	158	$ 0.76	$ 0.0031	155	$ 0.48	-$ 0.28	-36.76%
Sub-Total B - Delivery (including Sub-Total A)				**$ 12.02**			**$ 11.77**	**-$ 0.24**	**-2.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	158	$ 0.82	$ 0.0052	155	$ 0.81	-$ 0.02	-2.08%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	158	$ 0.17	$ 0.0011	155	$ 0.17	-$ 0.00	-2.08%
Special Purpose Charge	per kWh	$ -	158	$ -	$ -	155	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	158	$ 11.89	$ 0.0750	155	$ 11.64	-$ 0.25	-2.08%
Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 26.20**			**$ 25.69**	**-$ 0.51**	**-1.96%**
HST		13%		$ 3.41	13%		$ 3.34	-$ 0.07	-1.96%
Total Bill (including Sub-total B)				**$ 29.61**			**$ 29.03**	**-$ 0.58**	**-1.96%**

Loss Factor (%)	5.65%	3.45%
Threshold	750	750

Notes:

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PowerStream Barrie

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Bill Impacts - Monthly Consumptions

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monthly **Customer Class:** **Street Lighting**

per kWh **Consumption** **280** **kWh**
per kW **Load** **1.00** **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	monthly	$ 3.02	1	$ 3.02	$ 1.34	1	$ 1.34	-$ 1.68	-55.63%
Smart Meter Rate Adder	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Adder(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Service Charge Rate Rider(s)	monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 11.2961	1.00	$ 11.30	$ 5.8850	1.00	$ 5.89	-$ 5.41	-47.90%
Low Voltage Rate Adder	per kW	$ 0.2301	1.00	$ 0.23	$ 0.0918	1.00	$ 0.09	-$ 0.14	-60.10%
Volumetric Rate Adder(s)	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Volumetric Rate Rider(s)	per kW	-$ 0.4780	1.00	-$ 0.48	$ -	1.00	$ -	$ 0.48	-100.00%
Smart Meter Disposition Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ -	1.00	$ -	$ -	1.00	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider (2012) - effective until Apr 30, 2013	per kW	-$ 0.1545	1.00	-$ 0.15	-$ 0.1545	1.00	-$ 0.15	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider (2013) - effective until Dec.31, 2014	per kW			$ -	-$ 0.4548	1.00	-$ 0.45	-$ 0.45	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 13.91**			**$ 6.71**	**-$ 7.21**	**-51.79%**
RTSR - Network	per kW	$ 1.9589	1.00	$ 1.96	$ 1.9798	1.00	$ 1.98	$ 0.02	1.07%
RTSR - Line and Transformation Connection	per kW	$ 1.5002	1.00	$ 1.50	$ 0.8901	1.00	$ 0.89	-$ 0.61	-40.67%
Sub-Total B - Delivery (including Sub-Total A)				**$ 17.37**			**$ 9.58**	**-$ 7.80**	**-44.87%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	295.82	$ 1.54	$ 0.0052	290	$ 1.51	-$ 0.03	-2.08%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	295.82	$ 0.33	$ 0.0011	290	$ 0.32	-$ 0.01	-2.08%
Special Purpose Charge	per kWh	$ -	295.82	$ -	$ -	290	$ -	$ -	
Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	280	$ 1.96	$ 0.0070	280	$ 1.96	$ -	0.00%
Energy Tier 1	per kWh	$ 0.0750	296	$ 22.19	$ 0.0750	290	$ 21.72	-$ 0.46	-2.08%
Energy Tier 2	per kWh	$ 0.0880	-	$ -	$ 0.0880	-	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 43.63**			**$ 35.34**	**-$ 8.30**	**-19.01%**
HST		13%		$ 5.67	13%		$ 4.59	-$ 1.08	-19.01%
Total Bill (including Sub-total B)				**$ 49.31**			**$ 39.93**	**-$ 9.38**	**-19.02%**
Loss Factor (%)		5.65%			3.45%				
Threshold		750			750				

Notes:

Schedule 22

TAX RETURNS

Canada Revenue Agency Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 85750 3346 RC0002

Corporation's name
002 POWERSTREAM INC.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018.)
011 161 Cityview Blvd
012
City **015** VAUGHAN
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal code/Zip code **018** L4H 0A9

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028.)
021 c/o
022 161 Cityview Blvd
023
City **025** VAUGHAN
Province, territory, or state **026** ON
Country (other than Canada) **027**
Postal code/Zip code **028** L4H 0A9

Location of books and records
Has the location of books and records changed since the last time we were notified . . . . **030** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038.)
031 161 Cityview Blvd
032
City **035** VAUGHAN
Province,territory, or state **036** ON
Country (other than Canada) **037**
Postal code/Zip code **038** L4H 0A9

040 **Type of corporation at the end of the tax year**
1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2010-01-01 YYYY MM DD
Tax year-end **061** 2010-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . **065** YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with:
subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes ☐ 2 No ☒
subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒
Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	**150**	☐	9
Is the corporation an associated CCPC?	**160**	☐	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	**161**	☐	49
Does the corporation have any non-resident shareholders?	**151**	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	**162**	☐	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	**163**	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	**164**	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	**165**	☐	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	**166**	☐	T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	**167**	☐	T5013
Was the resident corporation the beneficiary of a non-resident discretionary trust or did it make a contribution to a non-resident discretionary trust at any time during the tax year?	**168**	☐	22
Did the corporation have any foreign affiliates during the year?	**169**	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	**170**	☐	29
Has the corporation had any non-arm's length transactions with a non-resident?	**171**	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	**173**	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	**172**	☐	———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	**201**	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	**202**	☒	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	**203**	☒	3
Is the corporation claiming any type of losses?	**204**	☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	**205**	☒	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	**206**	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	**207**	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	**208**	☒	8
Does the corporation have any property that is eligible capital property?	**210**	☒	10
Does the corporation have any resource-related deductions?	**212**	☐	12
Is the corporation claiming deductible reserves?	**213**	☐	13
Is the corporation claiming a patronage dividend deduction?	**216**	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	**217**	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	**218**	☐	18
Is the corporation carrying on business in Canada as a non-resident corporation?	**220**	☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	**221**	☐	21
Does the corporation have any Canadian manufacturing and processing profits?	**227**	☐	27
Is the corporation claiming an investment tax credit?	**231**	☒	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	**232**	☒	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	**233**	☒	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	**234**	☒	———
Is the corporation claiming a surtax credit?	**237**	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	**238**	☐	38
Is the corporation claiming a Part I tax credit?	**242**	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	**243**	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	**244**	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	**249**	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	**250**	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	**253**	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	**254**	☐	T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	**255**	☐	92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	**256**	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	**258**	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	**259**	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	**260**	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	**261**	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	**262**	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	**263**	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	**264**	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	**265**	☒	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	**266**	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	**267**	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	**268**	☒	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	**269**	☐	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	1 Yes ☐	2 No ☒
Is the corporation inactive?	**280**	1 Yes ☐	2 No ☒

What is the corporation's main revenue-generating business activity? .....

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	ELECTRICITY DISTRIBUTION	**285**	100.000 %
286		**287**	%
288		**289**	%

Did the corporation immigrate to Canada during the tax year?	**291**	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	**292**	1 Yes ☐	2 No ☒
Do you want to be considered as a quarterly instalment remitter if you are eligible?	**293**	1 Yes ☐	2 No ☐
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	**294**	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	**295**	1 Yes ☐	2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			**300**	32,813,266	A
Deduct: Charitable donations from Schedule 2	**311**	176,435			
Gifts to Canada, a province, or a territory from Schedule 2	**312**				
Cultural gifts from Schedule 2	**313**				
Ecological gifts from Schedule 2	**314**				
Gifts of medicine from Schedule 2	**315**				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	**320**				
Part VI.1 tax deduction*	**325**				
Non-capital losses of previous tax years from Schedule 4	**331**				
Net capital losses of previous tax years from Schedule 4	**332**				
Restricted farm losses of previous tax years from Schedule 4	**333**				
Farm losses of previous tax years from Schedule 4	**334**				
Limited partnership losses of previous tax years from Schedule 4	**335**				
Taxable capital gains or taxable dividends allocated from a central credit union	**340**				
Prospector's and grubstaker's shares	**350**				
Subtotal		176,435	▶	176,435	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				32,636,831	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			**355**		D
Taxable income (amount C **plus** amount D)			**360**	32,636,831	
Income exempt under paragraph 149(1)(t)			**370**		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				32,636,831	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	**400**	32,813,266	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 3.57143 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	**405**	32,636,831	B
Business limit (see notes 1 and 2 below)	**410**	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** **** 1,656,212 D / 11,250 = 73,609,422 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = **430** G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			32,636,831	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Amount used to calculate the credit union deduction from Schedule 17		D		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		E		
Aggregate investment income from line 440 on page 6*		F		
Total of amounts B to F		▶		G
Amount A **minus** amount G (if negative, enter "0")			32,636,831	H

Amount H	32,636,831	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	I
Amount H	32,636,831	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	= 3,263,683	J
Amount H	32,636,831	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	K
Amount H	32,636,831	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L 3,263,683 M
Enter amount M on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Amount used to calculate the credit union deduction from Schedule 17		Q		
Total of amounts O to Q		▶		R
Amount N **minus** amount R (if negative, enter "0")				S

Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	W

General tax reduction – Total of amounts T to W X
Enter amount X on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x 26 2 / 3 % = ... ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ______

Deduct:

Foreign investment income from Schedule 7 . . . . **445** ______ x 9 1 / 3 % = ______

(if negative, enter "0") ______ ▶ ______ B

Amount A **minus** amount B (if negative, enter "0") . . . . ______ C

Taxable income from line 360 on page 3 32,636,831

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ______

Foreign non-business income tax credit from line 632 on page 7 . . . ______ x 25 / 9 = ______

Foreign business income tax credit from line 636 on page 7 . . . . ______ x $\frac{1}{(0.38 - X^*)}$ 3.57143 = ______

______ ▶ ______

32,636,831

x 26 2 / 3 % = 8,703,155 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . 5,333,992 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ______ F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______

Deduct: Dividend refund for the previous tax year . . . . **465** ______

______ ▶ ______ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ______

Total Part IV tax payable from Schedule 3 . . . . ______

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______

______ ▶ ______ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . 10,532,000 x 1 / 3 3,510,667 I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . ______

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	550	12,401,996	A
Recapture of investment tax credit from Schedule 31	602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	32,636,831		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	32,636,831 ▶	32,636,831	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		12,401,996	D

Deduct:

Small business deduction from line 430 on page 4			1	
Federal tax abatement	608	3,263,683		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount M on page 5	638	3,263,683		
General tax reduction from amount X on page 5	639			
Federal logging tax credit from Schedule 21	640			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652	540,638		
Subtotal		7,068,004 ▶	7,068,004	E

Part I tax payable – Line D **minus** line E	5,333,992	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700		5,333,992
Part II surtax payable from Schedule 46	708		
Part III.1 tax payable from Schedule 55	710		
Part IV tax payable from Schedule 3	712		
Part IV.1 tax payable from Schedule 43	716		
Part VI tax payable from Schedule 38	720		
Part VI.1 tax payable from Schedule 43	724		
Part XIII.1 tax payable from Schedule 92	727		
Part XIV tax payable from Schedule 20	728		
Total federal tax			5,333,992

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	4,417,975	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		4,417,975 ▶	4,417,975
Total tax payable	770		9,751,967 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	9,246,731	
Total credits	890	9,246,731 ▶	9,246,731 B

Refund code **894** ☐ Overpayment ______ ◀ Balance (line A minus line B) 505,236

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 505,236

Enclosed payment **898** 505,236

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . **896** 1 Yes ☐ 2 No ☒

Certification

I, **950** LOMBARDI (Last name in block letters) **951** LUCY (First name in block letters) **954** VP, CORPORATE FINANCE (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 ______ Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation **956** (905) 532-4648 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . **957** 1 Yes ☒ 2 No ☐

958 ______ Name in block letters **959** ______ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

Privacy Act, Personal Information Bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact GERI YIN
Telephone number (905) 532-4635

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	INSTALMENTS PAID FOR THE YEAR	9,246,731

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	9,246,731	**A**
Total instalments credited to the taxation year per T9	9,246,731	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	175,909,000	212,380,000
	Total tangible capital assets	2008	+	1,246,432,000	1,185,602,000
	Total accumulated amortization of tangible capital assets	2009	–	604,373,000	583,838,000
	Total intangible capital assets	2178	+	61,801,000	58,852,000
	Total accumulated amortization of intangible capital assets	2179	–	15,078,000	12,695,000
	Total long-term assets	2589	+	85,886,000	88,742,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	950,577,000	949,043,000
	Liabilities				
	Total current liabilities	3139	+	170,877,000	171,863,000
	Total long-term liabilities	3450	+	493,083,000	508,933,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	663,960,000	680,796,000
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	286,617,000	268,247,000
	Total liabilities and shareholder equity	3640	=	950,577,000	949,043,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	36,999,000	21,064,000

* Generic item

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

Income statement information

Description **GIFI**

Operating name **0001**

Description of the operation **0002**

Sequence Number **0003** 01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	847,159,000	767,795,000
	Cost of sales	8518	–	691,318,000	
	Gross profit/loss	8519	=	155,841,000	767,795,000
	Cost of sales	8518	+	691,318,000	
	Total operating expenses	9367	+	128,015,000	748,059,000
	Total expenses (mandatory field)	9368	=	819,333,000	748,059,000
	Total revenue (mandatory field)	8299	+	856,388,000	777,684,000
	Total expenses (mandatory field)	9368	–	819,333,000	748,059,000
	Net non-farming income	9369	=	37,055,000	29,625,000
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	37,055,000	29,625,000
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	10,588,000	8,561,000
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	26,467,000	21,064,000

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SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes ☒ 2 No ☐

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes ☐ 2 No ☒

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 ☒

Completed a review engagement report . . . . . 2 ☐

Conducted a compilation engagement . . . . . 3 ☐

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 ☒

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 ☐

Were notes to the financial statements prepared? . . . . . **101** 1 Yes ☒ 2 No ☐

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes ☒ 2 No ☐

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes ☒ 2 No ☐

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes ☐ 2 No ☒

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . . **200** 1 Yes ☐ 2 No ☐

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . . **250** 1 Yes ☐ 2 No ☐

Did the corporation apply hedge accounting during the tax year? . . . . . . **255** 1 Yes ☐ 2 No ☐

Did the corporation discontinue hedge accounting during the tax year? . . . . . . **260** 1 Yes ☐ 2 No ☐

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . . **265** 1 Yes ☐ 2 No ☐

If **yes**, you have to maintain a separate reconciliation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

Assets – lines 1000 to 2599

1000	8,568,000	**1060**	69,366,000	**1120**	3,050,000
1480	92,207,000	**1484**	2,718,000	**1599**	175,909,000
1600	10,875,000	**1680**	53,225,000	**1681**	-7,689,000
1682	622,970,000	**1683**	-373,452,000	**1740**	471,248,000
1741	-191,837,000	**1900**	43,048,000	**1901**	-30,664,000
1910	18,280,000	**1911**	-731,000	**1920**	26,786,000
2008	1,246,432,000	**2009**	-604,373,000	**2010**	19,258,000
2011	-15,078,000	**2012**	42,543,000	**2178**	61,801,000
2179	-15,078,000	**2420**	31,961,000	**2421**	53,313,000
2424	612,000	**2589**	85,886,000	**2599**	950,577,000

Liabilities – lines 2600 to 3499

2620	105,339,000	**2680**	6,622,000	**2700**	40,000,000
2860	12,214,000	**2960**	5,224,000	**2961**	1,478,000
3139	170,877,000	**3320**	493,083,000	**3450**	493,083,000
3499	663,960,000				

Shareholder equity – lines 3500 to 3640

3500	249,618,000	**3600**	36,999,000	**3620**	286,617,000
3640	950,577,000				

Retained earnings – lines 3660 to 3849

3660	21,064,000	**3680**	26,467,000	**3700**	-10,532,000
3849	36,999,000				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	847,159,000	**8089**	847,159,000	**8230**	9,229,000
8299	856,388,000				

Cost of sales – lines 8300 to 8519

8320	691,318,000	**8518**	691,318,000	**8519**	155,841,000

Operating expenses – lines 8520 to 9369

8570	2,383,148	**8670**	46,675,096	**8710**	22,014,000
9270	56,942,756	**9367**	128,015,000	**9368**	819,333,000
9369	37,055,000				

Farming revenue – lines 9370 to 9659

9659 0

Farming expenses – lines 9660 to 9899

9898 0

Extraordinary items and taxes – lines 9970 to 9999

9970	37,055,000	**9990**	10,588,000	**9999**	26,467,000

Canada Revenue Agency Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				26,467,000	A
Add:					
Provision for income taxes – current		101	10,588,000		
Interest and penalties on taxes		103	6,863		
Amortization of tangible assets		104	46,675,096		
Amortization of intangible assets		106	2,383,148		
Loss on disposal of assets		111	532,505		
Charitable donations and gifts from Schedule 2		112	176,435		
Political donations		114	1,390		
Scientific research expenditures deducted per financial statements		118	159,101		
Non-deductible club dues and fees		120	33,934		
Non-deductible meals and entertainment expenses		121	99,599		
Non-deductible automobile expenses		122	8,807		
Reserves from financial statements – balance at the end of the year		126	17,233,493		
Subtotal of additions			77,898,371 ▶	77,898,371	
Other additions:					
Debt issue expense		208	674,448		
Financing fees deducted in books		216	11,832		
Miscellaneous other additions:					
600 Addback re: 12(1)(x)		290	23,036,647		
603 Ontario specific tax credits - CETC	83,862				
OITC/ORDTC/BCRDTC/ABRDTC from prior year - 12(1)(x)	20,505				
Total	104,367	293	104,367		
604					
Depreciation on stranded meters	1,047,116				
IFRS revenue deferred	869,164				
Amortization of deferred charges	32,000				
Interest on capital lease - building	1,087,716				
OM&A Capitalized for Accounting - SM	1,100,135				
Ontario specific tax credits - Apprenticeship	137,315				
Capital tax booked for accounting	560,784				
Total	4,834,230	294	4,834,230		
Subtotal of other additions		199	28,661,524 ▶	28,661,524	
Total additions		500	106,559,895 ▶	106,559,895	
Deduct:					
Capital cost allowance from Schedule 8		403	55,607,626		
Cumulative eligible capital deduction from Schedule 10		405	535,762		
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	1,639,541		
Reserves from financial statements – balance at the beginning of the year		414	14,043,639		
Subtotal of deductions			71,826,568 ▶	71,826,568	

Other deductions:

Miscellaneous other deductions:

700	BUSINESS RE-ENGINEERING		390	370,051	
701	S.13(7.4) ELECTION		391	23,036,647	
703	INTEREST CAPITALIZED FOR ACCOUNTING	1,513,430			
	Total	1,513,430	393	1,513,430	
704	Loan issue costs	193,270			
	IFRS costs deferred	485,984			
	Smart meter revenues accounting > tax	582,332			
	Capital lease treated as operating for tax	1,429,912			
	Canadian renewable and conservation expense	209,823			
	Deductible expenses capitalized for accounting	19,432			
	20(1)(e) deduction	2,366			
	CAPITAL TAX PER SCHEDULE 515	543,814			
	Total	3,466,933	394	3,466,933	
	Subtotal of other deductions		499	28,387,061 ►	28,387,061
	Total deductions		510	100,213,629 ►	100,213,629

Net income (loss) for income tax purposes – enter on line 300 of the T2 return 32,813,266

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SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- For use by corporations to claim any of the following:
  - – charitable donations;
  - – gifts to Canada, a province, or a territory;
  - – gifts of certified cultural property;
  - – gifts of certified ecologically sensitive land; or
  - – additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - – Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - – If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Georgian College	150,000
Women's Centre for York Region	375
Southlake Foundation	100
Markham Stouffville Hospital	15,000
CanadaHelps	100
Newtonbrook United Church	100
CanadaHelps	100
Yellowbrickhouse	1,000
Royal Victoria Hospital of Barrie Foundation	100
Hospice Caledon Foundation	100
CanadaHelps	100
CanadaHelps	100
United Way of York Region	200
Easter Seals	500
Alzheimer Society	100
George Hull Centre Foundation	500
Canadian Cancer Society	100
Beth Chabad Israeli Community	6,000
Crime Stopper	100
Princess Margaret Hospital Foundation	1,000
Heart Stroke Foundation	100
Royal Victoria Hospital of Barrie Foundation	100
Canadian Cancer Society	100
CanadaHelps	100
Canadian Cancer Society	100
Heart Stroke Foundation	100
Subtotal	176,275
Add: Total donations of less than $100 each	160
Total donations in current tax year	176,435

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year					
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240				
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) **210** 176,435					
Subtotal (line 250 **plus** line 210)		176,435		176,435	176,435
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available		176,435	A	176,435	176,435
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	176,435		176,435	176,435
Charitable donations closing balance	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2005-10-31			
7th prior year	2004-12-31			
8th prior year	2004-05-31			
9th prior year	2003-05-31			
10th prior year	2002-05-31			
11th prior year	2001-05-31			
12th prior year	2000-05-31			
13th prior year	1999-05-31			
14th prior year	1998-05-31			
15th prior year	1997-05-31			
16th prior year	1996-05-31			
17th prior year	1995-05-31			
18th prior year	1994-05-31			
19th prior year	1993-05-31			
20th prior year	1992-05-31			
21st prior year*	1991-05-31			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % . . . . . 24,609,950 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** . . . . . **225** ______ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) . . . . . **227** ______ D

The amount of the recapture of capital cost allowance in respect of charitable gifts . . . . . **230** ______

Proceeds of disposition, less outlays and expenses** . . . . . ______ E

Capital cost** . . . . . ______ F

Amount E or F, whichever is less . . . . . **235** ______

Amount on line 230 or 235, whichever is less . . . . . ______ G

Subtotal (**add** amounts C, D, and G) ______ H

Amount H **multiplied** by 25 % ______ I

Subtotal (amount B **plus** amount I) 24,609,950 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) . . . . . 176,435 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year . . . . . ______

Deduct: Gifts to Canada, a province, or a territory expired after five tax years . . . . . **339** ______

Gifts to Canada, a province, or a territory at the beginning of the tax year . . . . . **340** ______ ► ______

Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary . . . . . **350** ______

Total current-year gifts made to Canada, a province, or a territory* . . . . . **310** ______

Subtotal (line 350 **plus** line 310) ______

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) . . . . . **355** ______

Total gifts to Canada, a province, or a territory available . . . . . ______

Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return). . . . . . **360** ______

Gifts to Canada, a province, or a territory closing balance . . . . . **380** ______

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	**439**			
Gifts of certified cultural property at the beginning of the tax year	**440**			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	**450**			
Total current-year gifts of certified cultural property	**410**			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	**455**			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	**460**			
Gifts of certified cultural property closing balance	**480**			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2005-10-31			
7th prior year	2004-12-31			
8th prior year	2004-05-31			
9th prior year	2003-05-31			
10th prior year	2002-05-31			
11th prior year	2001-05-31			
12th prior year	2000-05-31			
13th prior year	1999-05-31			
14th prior year	1998-05-31			
15th prior year	1997-05-31			
16th prior year	1996-05-31			
17th prior year	1995-05-31			
18th prior year	1994-05-31			
19th prior year	1993-05-31			
20th prior year	1992-05-31			
21st prior year*	1991-05-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2005-10-31			
7th prior year	2004-12-31			
8th prior year	2004-05-31			
9th prior year	2003-05-31			
10th prior year	2002-05-31			
11th prior year	2001-05-31			
12th prior year	2000-05-31			
13th prior year	1999-05-31			
14th prior year	1998-05-31			
15th prior year	1997-05-31			
16th prior year	1996-05-31			
17th prior year	1995-05-31			
18th prior year	1994-05-31			
19th prior year	1993-05-31			
20th prior year	1992-05-31			
21st prior year*	1991-05-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal	Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640			
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

		Federal	Québec	Alberta
Subtotal (line 650**plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2005-10-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2009-12-31	
2nd prior year	2008-12-31	
3rd prior year	2007-12-31	
4th prior year	2006-12-31	
5th prior year	2005-12-31	
6th prior year*	2005-10-31	
7th prior year	2004-12-31	
8th prior year	2004-05-31	
9th prior year	2003-05-31	
10th prior year	2002-05-31	
11th prior year	2001-05-31	
12th prior year	2000-05-31	
13th prior year	1999-05-31	
14th prior year	1998-05-31	
15th prior year	1997-05-31	
16th prior year	1996-05-31	
17th prior year	1995-05-31	
18th prior year	1994-05-31	
19th prior year	1993-05-31	
20th prior year	1992-05-31	
21st prior year*	1991-05-31	
Total		

* These gifts expired in the current year.

T2 SCH 2 E (07)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend) 200	A	Complete if payer corporation is connected B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	Complete if payer corporation is connected G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270	
						J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: $\text{Part IV tax} = \frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)				
Deduct:				
Part IV.I tax payable on dividends subject to Part IV tax			320	
			Subtotal	
Deduct:				
Current-year non-capital loss claimed to reduce Part IV tax	330			
Non-capital losses from previous years claimed to reduce Part IV tax	335			
Current-year farm loss claimed to reduce Part IV tax	340			
Farm losses from previous years claimed to reduce Part IV tax	345			
Total losses applied against Part IV tax			x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)			360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	VAUGHAN HOLDINGS INC.		2010-12-31	4,772,576	
2	MARKHAM ENTERPRISES CORPORATION		2010-12-31	3,600,364	
3	BARRIE HYDRO HOLDINGS INC.		2010-12-31	2,159,060	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

		Total	10,532,000
Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	10,532,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)				10,532,000
Other dividends paid in the tax year (total of 510 to 540)				
Total dividends paid in the tax year			500	10,532,000
Deduct:				
Dividends paid out of capital dividend account	510			
Capital gains dividends	520			
Dividends paid on shares described in subsection 129(1.2)	530			
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540			
Subtotal			▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund				10,532,000

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

T2 SCH 5 E (11)

Canada

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
32,636,831		32,636,831	4,200,130

Ontario basic income tax (from Schedule 500)	270	4,240,109		
Deduct: Ontario small business deduction (from schedule 500)	402	39,979		
Subtotal		4,200,130	► 4,200,130	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272	39,979		
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal		39,979	► 39,979	B6
Subtotal (amount A6 **plus** amount B6)			4,240,109	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414	17,214		
Ontario political contributions tax credit (from Schedule 525)	415	181		
Subtotal		17,395	► 17,395	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			4,222,714	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416		127,376	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			4,095,338	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			4,095,338	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	543,814		
Subtotal		543,814	► 543,814	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			4,639,152	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	83,862		
Ontario apprenticeship training tax credit (from Schedule 552)	454	137,315		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
Subtotal		221,177	► 221,177	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		4,417,975	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 4,417,975

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		458,230,547	3,779,538		0	1,889,769	460,120,316	4	0	0	18,404,813	443,605,272
2.	2		65,246,552			0		65,246,552	6	0	0	3,914,793	61,331,759
3.	8		48,750,525	23,542,712		140,264	11,701,224	60,451,749	20	0	0	12,090,350	60,062,623
4.	10		8,458,152	2,603,685		0	1,301,843	9,759,994	30	0	0	2,927,998	8,133,839
5.	12		988,357	2,674,504		0	1,337,252	2,325,609	100	0	0	2,325,609	1,337,252
6.	17		554,567			0		554,567	8	0	0	44,365	510,202
7.		WORK-IN-PROGRESS	59,506,899		-34,395,391	0		25,111,508	0	0	0		25,111,508
8.	13	HYDRO VAUGHAN	17,605			0		17,605	NA	0	0	17,605	
9.	13	RICHMOND HILL				0			NA	0	0		
10.	13	MARKHAM HYDRO	200,789			0		200,789	NA	0	0	83,187	117,602
11.	45		721,383			0		721,383	45	0	0	324,622	396,761
12.	13	PS Inc - 2005 Additioin	18,265			0		18,265	NA	0	0	18,265	
13.	13		316,959			0		316,959	NA	0	0	101,978	214,981
14.	47		135,056,139	70,237,922		0	35,118,961	170,175,100	8	0	0	13,614,008	191,680,053
15.	50		640,531			0		640,531	55	0	0	352,292	288,239
16.	13	BARRIE HYDRO - right to use su	643,612			0		643,612	NA	0	0	31,395	612,217
17.	52			1,337,905		0		1,337,905	100	0	0	1,337,905	
18.	13	Addiscott Ops Centre		1,106,467		0	553,234	553,233	NA	0	0	18,441	1,088,026
19.	43.2	Solar business - Solar Panels		1,158,551		0	579,276	579,275	50	0	0		1,158,551
20.	47	Solar business - Distribution Equ		83,529		0	41,765	41,764	8	0	0		83,529
21.	12	Solar business - Software		4,128		0	2,064	2,064	100	0	0		4,128
		Totals	779,350,882	106,528,941	-34,395,391	140,264	52,525,388	798,818,780				55,607,626	795,736,542

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Canadä

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		105,422,474		
Additions for tax purposes – Schedule 8 leasehold improvements	+	1,106,467		
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
See attached	+	1,513,430		
Total additions per books	=	108,042,371	▶	108,042,371
Proceeds up to original cost – Schedule 8 regular classes		140,264		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
See attached	+			
Total proceeds per books	=	140,264	▶ –	140,264
Depreciation and amortization per accounts – Schedule 1			–	46,675,096
Loss on disposal of fixed assets per accounts			–	532,505
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	60,694,506

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		631,184,000
Opening net book value	–	595,725,830
Net change per financial statements	=	35,458,170

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount (Schedule 8Rec)

Description	Amount
Capitalized interest deducted for tax purposes	
Adds to Process reengineering deducted on schedule 1	
Smart meter additions per books, not included per tax	
Major tools adjustment	
Depreciation in land rights	
Total	

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount - S8Rec

Description	Amount
Smart meter additions in regulatory assets	
Adjustments to NBV of fixed assetes	
Computer additions in regulatory assets	
Total	

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter “0”) **200** 7,652,975 A

Add: Cost of eligible capital property acquired during the taxation year **222** 1,025

Other adjustments **226**

Subtotal (line 222 plus line 226) 1,025 x 3 / 4 = 769 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 769 ▶ 769 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 7,653,744 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . 7,653,744 K
(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 7,653,744

less amount from line 249

Current year deduction . . . . 7,653,744 x 7.00 % = **250** 535,762 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 535,762 ▶ 535,762 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 7,117,982 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount) . . . . N

Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 . . . . **400** 1

Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) **401** 2

Total of CEC deductions claimed for taxation years beginning before July 1, 1988 . . . . **402** 3

Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 **408** 4

Line 3 minus line 4 (if negative, enter "0") . . . . ▶ 5

Total of lines 1, 2 and 5 6

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 7

Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 8

Subtotal (line 7 plus line 8) **409** ▶ 9

Line 6 minus line 9 (if negative, enter "0") . . . . ▶ O

Line N minus line O (if negative, enter "0") . . . . P

Line 5 x 1 / 2 = Q

Line P minus line Q (if negative, enter "0") . . . . R

Amount R x 2 / 3 = S

Amount N or amount O, whichever is less . . . . T

Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1) **410**

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	EMPLOYEE FUTURE BENEFITS	12,036,282		1,970,718		14,007,000
2	ALLOWANCE FOR DOUBTFUL A	837,075		2,602,349	1,416,494	2,022,930
3	Unpaid Payroll - 2010	920,282		291,043	920,282	291,043
4	Inventory Obsolescence			313,382		313,382
5	Reserves in accruals	250,000		567,320	250,000	567,320
6	Donation accrual			31,818		31,818
7						
	Reserves from Part 2 of Schedule 13					
	Totals	14,043,639		5,776,630	2,586,776	17,233,493

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. All legislative references on this schedule are to the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2).
A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes ☐ 2 No ☒

Contributions to agricultural organizations for SR&ED . . . . . **103** ________

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.
For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.*
Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number **105**	Description of investment **110**	Date available for use **115**	Location used (province or territory) **120**	Amount of investment **125**

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year . . . .

Deduct:

Credit deemed as a remittance of co-op corporations **210**

Credit expired **215**

Subtotal ▶

ITC at the beginning of the tax year **220**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **230**

ITC from repayment of assistance **235**

Total current-year credit: total of column 125 ________ x 10 % = ... **240**

Credit allocated from a partnership **250**

Subtotal ▶

Total credit available . . . .

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) **260**

Credit carried back to the previous year(s) (from Part 6) . . . . A

Credit transferred to offset Part VII tax liability **280**

Subtotal ▶

Credit balance before refund . . . . B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) **310**

ITC closing balance of investments from qualified property **320**

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day			
1st previous tax year				Credit to be applied	**901**	
2nd previous tax year				Credit to be applied	**902**	
3rd previous tax year				Credit to be applied	**903**	

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) . . . . D

Refund (40 % of amount C or D, whichever is less) . . . . E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)	2,703,192		
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)	2,703,192 ►	350	2,703,192
Capital expenditures (from line 558 on Form T661)		360	
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	2,703,192

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes ☐ 2 No ☒

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied).		390	25,556,717
Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.	747,642,639	398	40,000,000

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . .

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . .

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ...

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A ____________ Amount B ____________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ____________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ____________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ____________ x $\frac{\text{Number of days in the tax year}}{365}$ 365 = ... ____________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ____________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=		J
Line 350 minus line 410 (if negative, enter "0")	430	2,703,192	x	20 %	=	540,638	K
Line 410 minus line 350 (if negative, enter "0")			L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=		M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=		N

Repayments (amount from line 370 in Part 8) ____________

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 %	=			
480		x	20 %	=			
			Total			▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) 540,638

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year					
Deduct:					
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
Subtotal			▶		
ITC at the beginning of the tax year			520		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	530				
Total current-year credit	540	540,638			
Credit allocated from a partnership	550				
Subtotal		540,638	▶	540,638	
Total credit available				540,638	
Deduct:					
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	540,638			
Credit carried back to the previous year(s) (from Part 13)			P		
Credit transferred to offset Part VII tax liability	580				
Subtotal		540,638	▶	540,638	
Credit balance before refund					Q
Deduct:					
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED			620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . **650** 1 Yes ☐ 2 No ☒

Credit balance before refund (amount Q from Part 12) . . . . R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) . . . . S

Refundable credits (amount R or S, whichever is less)* . . . . T

Amount J from Part 11 . . . . U

Subtract: Amount T or U, whichever is less V

Net amount (if negative, enter "0") . . . . W

Amount W x 40 % X

Add: Amount V . . . . Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%.
Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . AA

Amount J from Part 11 . . . . BB

Subtract: Amount AA or BB, whichever is less CC

Net amount (if negative, enter "0") . . . . DD

Amount M from Part 11 . . . . EE

Amount DD or EE, whichever is less x 40 % . . . . FF

Add : Amount CC above . . . . GG

Refund of ITC (amounts FF **plus** GG) . . . . HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter this amount on line LL in Part 17) ____________ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	**B** Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	**C** Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula (A x B) – C	**E** ITC earned by the transferee for the qualified expenditures that were transferred **750**	**F** Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) ____________ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ____________ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 . . . . ______ LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above . . . . ______ MM

Recaptured ITC for calculation 3 from line KK in Part 16 above . . . . ______ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN . . . . ______ OO
Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting . . . . **810** ______ PP
Geological, geophysical, or geochemical surveys . . . . **811** ______ QQ
Drilling by rotary, diamond, percussion, or other methods . . . . **812** ______ RR
Trenching, digging test pits, and preliminary sampling . . . . **813** ______ SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping . . . . **820** ______ TT
Sinking a mine shaft, constructing an adit, or other underground entry . . . . **821** ______ UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826 ______ ► ______ VV

Total pre-production mining expenditures (add amounts PP to VV) **830** ______

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above . . . . **832** ______

Excess (line 830 minus line 832) (if negative, enter "0") ______ W W

Add: Repayments of government and non-government assistance . . . . **835** ______ XX

Pre-production mining expenditures (amount WW plus amount XX) . . . . ______ YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year . . . .

Deduct:

Credit deemed as a remittance of co-op corporations **841**

Credit expired **845**

Subtotal ▶

ITC at the beginning of the tax year **850**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **860**

Expenditures from line YY in Part 18: **870** ______ x 10 % = ... **880**

Total credit available . . . .

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) **885**

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures **890**

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				. . . . Credit to be applied	**921**	
2nd previous tax year				. . . . Credit to be applied	**922**	
3rd previous tax year				. . . . Credit to be applied	**923**	

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . **611** 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Attach additional schedules if more space is needed.

A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**

Total current-year credit (enter at line 640)

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations **612**

Credit expired after 20 tax years **615**

Subtotal ▶

ITC at the beginning of the tax year **625**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **630**

ITC from repayment of assistance **635**

Total current-year credit (total of column 605) **640**

Credit allocated from a partnership **655**

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B4 in Part 30) **660**

Credit carried back to the previous year(s) (from Part 23) DDD

Subtotal ▶

ITC closing balance from apprenticeship job creation expenditures **690**

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	**931**	
2nd previous tax year				Credit to be applied	**932**	
3rd previous tax year				Credit to be applied	**933**	

Total (enter on line DDD in Part 22)

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number **665**	Description of investment **675**	Date available for use **685**	Amount of investment **695**
1.				

Total cost of depreciable property from the current tax year **715** EEE

Add: Specified child care start-up expenditures from the current tax year **705** FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) **725** HHH

Excess (amount GGG**minus** amount HHH) (if negative, enter "0") III

Add: Repayments of government and non-government assistance **735** JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) **745**

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745) . . . . ________ x 25 % = ________ KKK

Number of child care spaces . . . . **755** ________ x $ 10,000 = ________ LLL

ITC from child care spaces expenditures (amount KKK or LLL, whichever is less) . . . . ________ MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year . . . . ________

Deduct:

Credit deemed as a remittance of co-op corporations . . . . **765** ________

Credit expired after 20 tax years . . . . **770** ________

Subtotal ________ ▶ ________

ITC at the beginning of the tax year . . . . **775** ________

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . **777** ________

Total current-year credit (amount MMM above) . . . . **780** ________

Credit allocated from a partnership . . . . **782** ________

Subtotal ________ ▶ ________

Total credit available . . . . ________

Deduct:

Credit deducted from Part I tax (enter on line B5 in Part 30) . . . . **785** ________

Credit carried back to the previous year(s) (from Part 27) . . . . ________ NNN

Subtotal ________ ▶ ________

ITC closing balance from child care spaces expenditures . . . . **790** ________

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2009-12-31	Credit to be applied	**941**	
2nd previous tax year	2008-12-31	Credit to be applied	**942**	
3rd previous tax year	2007-12-31	Credit to be applied	**943**	

Total (enter on line NNN in Part 26) ________

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ____________ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ____________

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ____________

Amount from line 795 or line 797, whichever is less . . . . ____________ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ____________ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . ____________ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 . . . . ____________ A1

Recaptured child care spaces ITC from line QQQ in Part 28 above . . . . ____________ A2

Total recapture of investment tax credit – Add lines A1 and A2 . . . . ____________ A3
Enter amount A3 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . ____________ B1

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) 540,638 B2

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . ____________ B3

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) . . . . ____________ B4

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . ____________ B5

Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) 540,638 B6
Enter amount B6 at line 652 of the T2 return.

Privacy Act, Personal Information Bank number CRA PPU 047

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
540,638	540,638			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2005-10-31				
2004-12-31				
2004-05-31				
2003-05-31				
2002-05-31				*
2001-05-31				
2000-05-31				
1999-05-31				
1998-05-31				
1997-05-31				
1996-05-31				
1995-05-31				
1994-05-31				
1993-05-31				
1992-05-31				*
Total				

B+C+D+G **Total ITC utilized** 540,638

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	17,233,493		
Capital stock (or members' contributions if incorporated without share capital)	103	249,618,000		
Retained earnings	104	36,999,000		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	496,295,149		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	3,730		
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112			
Subtotal		800,149,372 ▶	800,149,372	A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121	53,252,000		
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal		53,252,000 ▶	53,252,000	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		746,897,372	

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	803,215
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	803,215

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		746,897,372	C
Deduct: Investment allowance for the year (line 490)		803,215	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	746,094,157	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 746,094,157 x $\frac{\text{Taxable income earned in Canada} \quad \textbf{610} \quad 32{,}636{,}831}{\text{Taxable income} \quad 32{,}636{,}831}$ = **Taxable capital employed in Canada** 690 746,094,157

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			701		
Deduct the following amounts:					
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711				
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712				
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713				
Total deductions (add lines 711, 712, and 713)			►		E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			790		

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	746,094,157	F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")	736,094,157	H
Calculation for purposes of the small business deduction (amount H x 0.00225)	1,656,212	I

Enter this amount at line 415 of the T2 return

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Loans & Advances To Corporation

Description	Amount	
DUE TO RELATED PARTIES	12,214,000	00
CURRENT PORTION OF CUSTOMER'S DEPOSIT	1,478,000	00
NON CURRENT PORTION OF CUSTOMER'S DEPOSIT	12,071,000	00
NON CURRENT PORTION OF CONSTRUCTION DEPOSIT	23,364,000	00
CURRENT PORTION OF LIABILITY FOR SUBDIVISION DEVELOPMENT	4,138,000	00
NOTES PAYABLE	182,430,000	00
DEBENTURES PAYABLE	123,765,000	00
REGULATORY LIABILITIES	36,353,000	00
OTHER LIABILITIES	160,000	00
LONG TERM BANK LOAN	50,000,000	00
SHORT TERM BANK LOAN	40,000,000	00
NON CURRENT PORTION OF LIABILITY FOR SUBDIVISION DEVELOPMENT	1,232,000	00
CUSTOMER CREDIT BALANCES	8,263,149	00
INFRASTRUCTURE ONTARIO FINANCING	827,000	00
Total	496,295,149	00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	VAUGHAN HOLDINGS INC.				45.315	
2	MARKHAM ENTERPRISES CORPORATION				34.185	
3	BARRIE HYDRO HOLDINGS INC.				20.500	
4						
5						
6						
7						
8						
9						
10						

Canada

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

On: 2010-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act.*
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year . . . . 100 89,402,400 A

Taxable income for the year (DICs enter "0") * . . . . 110 32,636,831 B

Income for the credit union deduction *
(amount E in Part 3 of Schedule 17) 120

Amount on line 400, 405, 410, or 425 of
the T2 return, whichever is less * 130

For a CCPC, the lesser of aggregate investment income
(line 440 of the T2 return) and taxable income * 140

Subtotal (**add** lines 120, 130, and 140) ▶ C

Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0") . . . 150 32,636,831

After-tax income (line 150 x general rate factor for the tax year ** 0.69) . . . . 190 22,519,413 D

Eligible dividends received in the tax year 200

Dividends deductible under section 113 received in the tax year 210

Subtotal (**add** lines 200 and 210) ▶ E

GRIP addition:

Becoming a CCPC (line PP from Part 4) 220

Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4) 230

Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4) 240

Subtotal (**add** lines 220, 230, and 240) ▶ 290 F

Subtotal (**add** lines A, D, E, and F) 111,921,813 G

Eligible dividends paid in the previous tax year 300

Excessive eligible dividend designations made in the previous tax year 310

Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 **minus** line 310) ▶ H

GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative) 490 111,921,813

Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2) 560

GRIP at the end of the tax year (line 490 **minus** line 560) 590 111,921,813

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2009-12-31

Taxable income before specified future tax consequences
from the current tax year 25,556,717 J1

Enter the following amounts before specified future tax
consequences from the current tax year:

Income for the credit union deduction
(amount E in Part 3 of Schedule 17) . . . K1

Amount on line 400, 405, 410, or 425
of the T2 return, whichever is less L1

Aggregate investment income
(line 440 of the T2 return) M1

Subtotal (**add** lines K1, L1, and M1) ▶ N1

Subtotal (line J1 **minus** line N1) (if negative, enter "0") 25,556,717 ▶ 25,556,717 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R1

Aggregate investment income (line 440 of the T2 return) . . . . ____ S1

Subtotal (**add** lines Q1, R1, and S1) ____ ▶ ____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ____ ▶ ____ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ____ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.68) . . . . **500** ____

Second previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 18,142,389 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ L2

Aggregate investment income (line 440 of the T2 return) . . . . ____ M2

Subtotal (**add** lines K2, L2, and M2) ____ ▶ ____ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 18,142,389 ▶ 18,142,389 O2

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R2

Aggregate investment income (line 440 of the T2 return) . . . . ____ S2

Subtotal (**add** lines Q2, R2, and S2) ____ ▶ ____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ____ ▶ ____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ____ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.68) . . . . **520** ____

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 35,294,289 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ________ L3

Aggregate investment income (line 440 of the T2 return) 2,165,279 M3

Subtotal (**add** lines K3, L3, and M3) 2,165,279 ▶ 2,165,279 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 33,129,010 ▶ 33,129,010 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ________ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ________ R3

Aggregate investment income (line 440 of the T2 return) . . . . ________ S3

Subtotal (**add** lines Q3, R3, and S3) ________ ▶ ________ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ________ ▶ ________ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ________ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.68) . . . . **540** ________

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ________ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ________ AA

Eligible dividends paid by the corporation in its last tax year . . . . ________ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ________ CC

Subtotal (line BB **minus** line CC) ________ ▶ ________ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . ________ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ______ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ______

Net capital losses . . . . ______

Farm losses . . . . ______

Restricted farm losses . . . . ______

Limited partnership losses . . . . ______

Subtotal ______ ▶ ______ HH

Subtotal (**add** lines FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ______ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ______ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ______ ▶ ______ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010		. . . . =		QQ
		number of days in the tax year	365			
0.69	x	number of days in the tax year in 2010	365	. . . . =	0.69000	RR
		number of days in the tax year	365			
0.7	x	number of days in the tax year in 2011		. . . . =		SS
		number of days in the tax year	365			
0.72	x	number of days in the tax year after December 31, 2011		. . . . =		TT
		number of days in the tax year	365			

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.69000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		10,532,000			
Total taxable dividends paid in the tax year	100	10,532,000			
Total eligible dividends paid in the tax year			150		
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	111,921,813	
Excessive eligible dividend designation (line 150 **minus** line 160)					A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC * (amount A **multiplied** by 20 %)			190		

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)					B
Part III.1 tax on excessive eligible dividend designations – Other corporations * (amount B **multiplied** by 20 %)			290		

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references on this schedule are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	14.00 %	=	6.94247 %	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	12.00 %	=	6.04932 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 12.99179 ▶ 12.99179 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 32,636,831 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . . . 4,240,109 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return) 32,813,266 1

Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) 32,636,831 2

Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) . . . . . 500,000 x 500,000 / 500,000 (line 4 on page 4 of the T2 return *) = 500,000 3

Enter the least of amounts 1, 2, and 3 . . . . . 500,000 D

Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories *** = 32,636,831.00 / 32,636,831 = ... 1.00000 E

Amount D x amount E 500,000 a

Ontario taxable income (amount B from Part 2) 32,636,831 b

Ontario small business income (lesser of amount a and amount b) . . . . . 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	8.50 %	=	4.21507 %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	7.50 %	=	3.78082 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5

OSBD rate for the year (total of rates G1 to G5) . . . . . 7.99589 % G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . . . 39,979 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	32,636,831	I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)		J		
Aggregate adjusted taxable income (amount I **plus** amount J)	32,636,831	▶	32,636,831	K
Deduct:				
Ontario business limit			500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)			32,136,831	L

Small business surtax rate for the year:

$$\frac{\text{Number of days in the tax year before July 1, 2010}}{\text{Number of days in the tax year}} \quad \frac{181}{365} \quad \times \quad 4.25\ \% \quad = \quad 2.10753\ \%\ \text{M}$$

Amount L x % on line M = 677,293 N

Amount N 677,293 x $\frac{\text{Ontario small business income (amount F from Part 3)}}{500,000}$ $\frac{500,000}{500,000}$ = 677,293 O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) 39,979 P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 500,000 Q

$$\frac{\text{Surtax payable (amount P from Part 4)}}{\text{Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3)}\ 7.99589\ \%} \quad \frac{39,979}{0.07996} = 499,987\ \text{R}$$

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") 13 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17 . . . . ________ T

Deduct:

Ontario adjusted small business income (amount S from Part 5) . . . . ________ U

Subtotal (amount T **minus** amount U) (if negative, enter "0") . . . . ________ V

OSBD rate for the year (rate G6 from Part 3) . . . . 7.99589 %

Amount V **multiplied** by the OSBD rate for the year . . . . ________ W

Ontario domestic factor (amount E from Part 3) . . . . 1.00000 X

Ontario credit union tax reduction (amount W **multiplied** by amount X) . . . . ________ Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, references to parts, sections, subsections, paragraphs, subparagraphs, and clauses are from the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	**110**	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	**112**	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	**114**	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	**116**	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	**118**	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	**120**	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	**122**	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	**124**	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	**128**	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	**130**	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	**132**	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	**134**	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	**136**	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	**150**	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	**152**	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	**154**	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	**160**		
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	**162**		
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	**164**		
Federal balance before election (total of lines 110 to 164)			A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	**170**	
Total federal balance (amount A **minus** line 170)	**180**	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*) . . . . . 210 ______

Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1) . . . . . 212 ______

Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1) . . . . . 214 ______

Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1) . . . . . 216 ______

Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1) . . . . . 218 ______

Gifts of medicine (see Note 1) . . . . . 220 ______

Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*) . . . . . 222 ______

Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3) . . . . . 224 ______

Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5) . . . . . 226 ______

Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2) . . . . . 228 ______

Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2) . . . . . 230 ______

Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2) . . . . . 232 ______

Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4) . . . . . 234 ______

Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4) . . . . . 236 ______

Amounts included In the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) . . . . . 250 ______

One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) . . . . . 252 ______

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6) . . . . . 260 ______

Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year . . . . . 262 ______

Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario) . . . . . 264 ______

Total Ontario balance (total of lines 210 to 264) . . . . . 280 ______

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of federal Act in a tax year ending prior to the start of the tax year ending immediately before the corporation's transition time; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year) **300** 581,525,479

Add:

Amount from eligible amalgamation* **310**
Amount from eligible post-2008 windup* **315**
Amount from eligible pre-2009 windup* **320**
Amount from specified pre-2009 transfers* **325**

Total federal balance at the end of the tax year . . . . . 581,525,479 ▶ **330** 581,525,479

Total Ontario balance:

Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year) **340** 582,187,991

Add:

Amount from eligible amalgamation* **350**
Amount from eligible post-2008 windup* **355**
Amount from eligible pre-2009 windup* **360**
Amount from specified pre-2009 transfers* **365**

Total Ontario balance at the end of the tax year . . . . . 582,187,991 ▶ **370** 582,187,991

Transitional balance at the end of the tax year (line 330 **minus** line 370) . . . . . **390** -662,512

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation*.

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? . . . . . **400** 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1) . . . . . B

Deduct:

Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2) 1

Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2) 2

Subtotal (amount 1 **plus** amount 2) ▶ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") D

Federal balance before election (amount A from Part 1) . . . . .

Deduct:

Total Ontario balance (amount from line 280 in Part 2) . . . . .

Subtotal (if negative, enter "0") E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

- five calendar years after the time immediately before the start of the corporation's reference period; or
- December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:

- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
- the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

- the end of the corporation's reference period; or
- the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:

- the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
- the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:

- enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435** ______
- enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) . . . . **440** ______

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

Ontario taxable income* / Taxable income** ______ = ______

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3				G
Amount G x Ontario basic rate of tax*	12.99179 % =			H
Amount H x OAF (from line F in Part 6)	1.00000			I
Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5	365 / 1,825	=	0.20000	J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J)			K
Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	**460**		
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	**470**		
Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470)			L
Total transitional tax debits (amount K **plus** amount L)			M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5		4,240,109	N
Deduct:			
Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
Subtotal	▶		O
Subtotal (amount N **minus** amount 0)		4,240,109	P
Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012)	365 / 365 =	1.00000	Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q)	**510**	4,240,109	

Amount from line 390 in Part 3 (enter as a positive amount)		662,512	R
Amount R x Ontario basic rate of tax*	12.99179 % =	86,072	S
Amount S x OAF (from line F in Part 6)		86,072	T
Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5	365 / 1,825 =	0.20000	U

Current-year transitional tax credit (amount T **multiplied** by amount U)	**520**	17,214	
Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0")	**530**	4,222,895	
Transitional tax credit:			
Lesser of amounts on line 510 and 520		17,214	V
Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530			W
Transitional tax credit (amount V **plus** amount W)		17,214	X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*			1		
Add:					
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560		2		
Unused transitional tax credit available (amount 1 **plus** amount 2)			▶		Y
Add:					
Current-year transitional tax credit (amount from line 520 in Part 8)				17,214	Z
Subtotal (amount Y **plus** amount Z)				17,214	3
Deduct:					
Transitional tax credit applied (amount X from Part 8)				17,214	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)			580		

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610				
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614				
Repayment of assistance under paragraph 37(1)(c)	618				
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624				
Subtotal (total of lines 610 to 624)			▶		BB
Deduct:					
Assistance under paragraph 37(1)(d)	638				
Investment tax credits deducted under paragraph 37(1)(e)	644				
Subtotal (line 638 **plus** line 644)			▶		CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)			650		

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

– the corporation's OAF for the tax year that includes its transition time (from line F in Part 6)	%		
– the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario)	%		
– the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008	%		
Relevant OAF		660	%

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

- the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;
2) a corporation that wound up into the particular corporation under subsection 88(1); or
3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . ________ DD

SR&ED expenditure amount deducted in the year under subsection 37(1) . . . . **670** ________

Deduct:

Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) . . . . . **675** ________

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ________ ► ________ EE

Subtotal (amount DD **plus** amount EE) ________ FF

Amount FF x 14 % ________ GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . ________ HH

Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) . . . . ________ II

Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 . . . . **700** ________

Subtotal (line II **plus** line 700) ________ JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 . . . . **705** ________

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . **710** ________

Deduct:

Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year . . . . **715** ________

Subtotal (line 710 **minus** line 715) **720** ________

$$\frac{\text{Line 720}}{\text{Relevant OAF (from line 660 in Part 11) x 14 \%}} = \_\_\_\_\_\_\_\_$$ . . . . . . ________ KK

Subtotal (line 705 **minus** amount KK) ________ ► **730** ________

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") . . . . ________ LL

Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . **735** ________ MM

Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . ________ NN

Amount NN x 14 % . . . . ________ ► ________ OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up . . . . **740** ________

Subtotal (amount OO **plus** line 740) ________ PP

Deduct:

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) . . . . **750** ________

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . ________ QQ

Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	2,830,568	A			
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B			
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		2,830,568	C			
Add: Eligible expenditures transferred to the corporation by another corporation	110		D			
Subtotal (amount C **plus** amount D)		2,830,568	▶		2,830,568	E
Deduct: Eligible expenditures the corporation transferred to another corporation				115		F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")				120	2,830,568	G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)					2,830,568	x 4.50 % =	200	127,376	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *							205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment				210		x 4.50 % =	215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220		x 1 / 4 =			x 4.50 % =	225		K
Current part of the ORDTC (total of amounts H to K)							230	127,376	L

* If there is a disposal or change of use of eligible property, see Part 6

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year . . . . _______ M

Deduct: ORDTC expired after 20 tax years . . . . **300** _______ N

ORDTC at the beginning of the tax year (amount M **minus** amount N) . . . . **305** _______ O

Add:

ORDTC transferred on amalgamation or windup . . . . **310** _______ P

Current part of ORDTC (amount L in Part 2) . . . . 127,376 Q

Are you waiving all or part of the current part of the ORDTC? . . . . . . **315** Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC . . . . **320** _______ R

Subtotal (amount Q **minus** amount R) 127,376 ▶ 127,376 S

ORDTC available for deduction (total of amounts O, P and S) . . . . 127,376 ▶ 127,376 T

Deduct:

ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*) . . . . 127,376 U

ORDTC carried back to a previous tax year (from Part 4) . . . . _______ V

Subtotal (amount U **plus** amount V) 127,376 ▶ 127,376 W

ORDTC balance at the end of the tax year (amount T **minus** amount W) . . . . **325** _______ X

* This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount T); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year	Month	Day			
1st previous tax year	2009-12-31			. . . . Credit to be applied	**901**	
2nd previous tax year	2008-12-31			. . . . Credit to be applied	**902**	
3rd previous tax year	2007-12-31			. . . . Credit to be applied	**903**	

Total (enter amount on line V in Part 3) _______

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available		Tax year of origin (earliest tax year first) Year Month Day	Credit available
1992-05-31			2002-05-31	
1993-05-31			2003-05-31	
1994-05-31			2004-05-31	
1995-05-31			2004-12-31	
1996-05-31			2005-10-31	
1997-05-31			2005-12-31	
1998-05-31			2006-12-31	
1999-05-31			2007-12-31	
2000-05-31			2008-12-31	
2001-05-31			2009-12-31	
		Current tax year	2010-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Z Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act **720**	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition **730**	EE The amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) **740**
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred **750**	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . **760** ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures		**Capital Expenditures**	
Total expenditures for SR&ED		2,253,509			
Add					
• payment of prior years' unpaid expenses (other than salary or wages)	+				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+	577,059			
• expenditures on shared-use equipment			+		
• other additions	+		+		
Subtotal	=	2,830,568	=		
Less					
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–				
• prescribed expenditures not allowed by regulations	–		–		
• other deductions	–		–		
• non-arm's length transactions					
– expenditures for non-arm's length SR&ED contracts	–				
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–		
Subtotal	=	2,830,568 I	=		II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			=	2,830,568	III

Enter amount III on line 100 of Schedule 508.

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	950,577,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		950,577,000
Total revenue of the corporation for the tax year **	142	856,388,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		856,388,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	26,467,000	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	10,588,000			
Provision for deferred income taxes (debits)/cost of future income taxes	222				
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		10,588,000	▶	10,588,000	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal			▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	37,055,000	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 37,055,000

Deduct:

CMT loss available (amount R from Part 7) . . . .

Minus: Adjustment for an acquisition of control * **518**

Adjusted CMT loss available . . . . ▶ C

Net income subject to CMT calculation (if negative, enter "0") **520** 37,055,000

Amount from line 520	37,055,000	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x 4 % =	735,009 1
Amount from line 520	37,055,000	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	184 / 365	x 2.7 % =	504,354 2

Subtotal (amount 1 **plus** amount 2) 1,239,363 3

Gross CMT: amount on line 3 above x OAF ** **540** 1,239,363

Deduct:

Foreign tax credit for CMT purposes *** **550**

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . 1,239,363 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 4,095,338

Net CMT payable (if negative, enter "0") . . . . E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year * . . . . G

Deduct:

CMT credit expired * **600**

CMT credit carryforward at the beginning of the current tax year * (see note below) . . . . ▶ **620**

Add:

CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) **650**

CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) . . . . H

Deduct:

CMT credit deducted in the current tax year (amount P from Part 5) I

Subtotal (amount H **minus** amount I) J

Add:

Net CMT payable (amount E from Part 3) . . . .

SAT payable (amount O from Part 6 of Schedule 512) . . . .

Subtotal ▶ K

CMT credit carryforward at the end of the tax year (amount J **plus** amount K) . . . . **670** L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4) . . . . M

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 4,095,338 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 1,239,363 2

For a life insurance corporation:

Gross CMT (line 540 from Part 3) 3

Gross SAT (line 460 from Part 6 of Schedule 512) 4

The **greater** of amounts 3 and 4 5

Deduct: line 2 or line 5, whichever applies: 1,239,363 6

Subtotal (if negative, enter "0") 2,855,975 ▶ 2,855,975 N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 4,095,338

Deduct:

Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) 221,177

Subtotal (if negative, enter "0") 3,874,161 ▶ 3,874,161 O

CMT credit deducted in the current tax year (least of amounts M, N, and O) . . . . P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? . . . . **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ________ Q

Deduct:

CMT loss expired * . . . . 700 ________

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ________ ▶ 720 ________

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . 750 ________

CMT loss available (line 720 **plus** line 750) . . . . ________ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ________

Subtotal (if negative, enter "0") ________ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . 760 ________

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 ________ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	**810**	**820**
9th previous tax year	**811**	**821**
8th previous tax year	**812**	**822**
7th previous tax year	**813**	**823**
6th previous tax year	**814**	**824**
5th previous tax year	**815**	**825**
4th previous tax year	**816**	**826**
3rd previous tax year	**817**	**827**
2nd previous tax year	**818**	**828**
1st previous tax year		**829**
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- The Ontario capital tax is eliminated effective July 1, 2010. You do not have to complete this schedule if the corporation's tax year begins after June 30, 2010. For businesses mainly engaged in qualifying manufacturing and resource activities in Ontario, the capital tax is eliminated effective January 1, 2007.
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations* (renamed *Taxable Capital Employed in Canada – Large Corporations* for 2010 and later tax years). File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	800,149,372		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		800,149,372 ▶	800,149,372	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	53,252,000		
Amount on line 490 from Part 2 of Schedule 33	115	803,215		
Subtotal		54,055,215 ▶	54,055,215	B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")	120		746,094,157	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? 190 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33) 200 ______ / Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year * 210 ______ x 15,000,000 $ = **Capital deduction** 220 ______

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) / Ontario allocation factor (OAF) (amount I in Part 3) 300 ______ = **Capital deduction** 305 ______

T2 SCH 515 E (10)

Canada

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies **320** 746,094,157

Deduct:

Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) . . . . 15,000,000 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . 731,094,157 C

Note: For days in the tax year after June 30, 2010, the Ontario capital tax rate is 0%.

Amount C	731,094,157	x	Number of days in the tax year before January 1, 2010 Number of days in the tax year	 365	x	0.00225	=		D
Amount C	731,094,157	x	Number of days in the tax year after December 31, 2009 and before July 1, 2010 Number of days in the tax year	181 365	x	0.00150	=	543,814 E

Subtotal (amount D **plus** amount E) 543,814 F

Amount F	543,814	x	OAF (amount on line I)	1.00000	=	543,814 G
Amount G	543,814	x	Number of days in the tax year * 365	365 365	=	543,814 H

Deduct:

Capital tax credit for manufacturers (enter amount J from Part 4) **350**

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 543,814

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** =

Ontario allocation factor . . . . 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* **405** / Total Ontario labour cost** **410** x 100 = ... **420** %

If the percentage on line 420 is 20% or less, enter "0" on line J.

If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.

If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% % / 30 % x 543,814 Amount H from Part 3 =

Capital tax credit for manufacturers . . . . J

Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)

** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 525

ONTARIO POLITICAL CONTRIBUTIONS TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule if you are a corporation and you want to:
  - calculate an Ontario political contributions tax credit (OPCTC) under section 53.2 of the *Taxation Act, 2007* (Ontario).
  - claim an OPCTC for eligible contributions made in the tax year or for unused eligible contributions carried forward from any of the previous 20 tax years to reduce Ontario corporate income tax payable.
- The OPCTC is a non-refundable tax credit that is calculated by **multiplying** the corporation's Ontario basic rate of tax (calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*) by the eligible contributions made to a registered candidate, a registered constituency association, or a registered party. Registered candidate, registered constituency association, and registered party are defined in the *Election Finances Act* (Ontario).
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Eligible contribution balance at the end of the tax year

Eligible contribution balance at the end of the previous tax year*			A		
Deduct: Unused eligible contributions expired after 20 tax years	100		B		
Eligible contribution balance at the beginning of the tax year (amount A **minus** amount B)*	110		C		
Add: Eligible contributions for the current tax year	120	1,390	D		
Eligible contribution balance available (amount C **plus** amount D)		1,390 ▶		1,390	E
Deduct: Eligible contributions used to claim the tax credit in the current tax year (amount M from Part 2)				1,390	F
Eligible contribution balance at the end of the tax year (amount E **minus** amount F)	190				G

* For the first tax year that includes days in 2009:
- do not enter an amount on line A or line 100
- for line 110, enter the Ontario balance at the end of the year from Ontario Schedule 2A, *Ontario Political Election Contributions*, for the last tax year that ended in 2008, if applicable. If you entered an amount on line 110 from Schedule 2A, complete Part 3.

For other tax years, enter on line A the amount from line 190 of Schedule 525 from the previous tax year, if applicable.

Part 2 – Calculation of current year OPCTC

Eligible contribution balance available (amount E from Part 1) . . . 1,390 H

(Lesser of $ 18,600 and amount H) 1,390 x Ontario basic rate of tax * 12.99179 % = . . . 181 I

Ontario corporate income tax payable before OPCTC, Ontario research and development tax credit, Ontario corporate minimum tax credit, and any Ontario refundable tax credit ** . . . 4,222,895 J

Maximum allowable current year OPCTC (lesser of amounts I and J) . . . 181 K

OPCTC claimed (cannot exceed amount K) . . . 181 L
Enter amount L on line 415 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

Eligible contributions used: OPCTC claimed (amount L) 181 ÷ Ontario basic rate of tax * 12.99179 % = . . . 1,390 M
Enter amount M on line F in Part 1.

* Enter the rate calculated in Part 1 of Schedule 500.
** Enter the result of amount C6 **minus** the total of amounts from lines 404 to 414, from Schedule 5.

Part 3 – Analysis of eligible contribution balance available for carryforward by tax year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal *Income Tax Act*.

Year of origin	Eligible contribution balance*
20th previous tax year	**350**
19th previous tax year	**351**
18th previous tax year	**352**
17th previous tax year	**353**
16th previous tax year	**354**
15th previous tax year	**355**
14th previous tax year	**356**
13th previous tax year	**357**
12th previous tax year	**358**
11th previous tax year	**359**

Year of origin	Eligible contribution balance*
10th previous tax year	**360**
9th previous tax year	**361**
8th previous tax year	**362**
7th previous tax year	**363**
6th previous tax year	**364**
5th previous tax year	**365**
4th previous tax year	**366**
3rd previous tax year	**367**
2nd previous tax year	**368**
1st previous tax year	**369**
Total**	

* Eligible contributions that were made in each of the previous 20 tax years and have not been used.

** The total of all the tax years must equal the amount entered on line 110 in Part 1.

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
POWERSTREAM INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent	Year Month Day	**120** Ontario Corporation No.
Ontario		2009-01-01	1677786

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
161	CITYVIEW BLVD	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
VAUGHAN	ON	CA	L4H 0A9

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 LOMBARDI — Last name

451 LUCY — First name

454 , — Middle name(s)

460 1 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number

530 Street name/Rural route/Lot and Concession number

540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)

570 Province/state

580 Country

590 Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
LUCY LOMBARDI	(905) 532-4648

Is the claim filed for a CETC earned through a partnership?* . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 8,767,651

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Humber College	
2.	Georgian College	
3.	Georgian College	
4.	Centennial College	
5.	Georgian College	
6.	Georgian College	
7.	Georgian College	
8.	ETH Zurich	
9.	Georgian College	
10.	Ryerson University	
11.	Georgian College	
12.	Seneca College	
13.	Georgian College	
14.	Fleming College	
15.	Georgian College	
16.	Georgian College	
17.	Ryerson University	
18.	Georgian College	
19.	Georgian College	
20.	Georgian College	
21.	Humber College	
22.	Georgian College	
23.	Georgian College	

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	Georgian College	
25.	Georgian College	
26.	Georgian College	
27.	Georgian College	
28.	Georgian College	
29.	Georgian College	
30.	Georgian College	
31.	Georgian College	
32.	Georgian College	
33.	Georgian College	
34.	Georgian College	
35.	Georgian College	
36.	Georgian College	
37.	Georgian College	
38.	Georgian College	

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	DE SANCTIS, LAURA	2010-01-01	2010-01-08
2.	JEFFREYS, ADAM	2010-01-01	2010-01-08
3.	HASTIE, DAVID	2010-12-20	2010-12-31
4.	TOVERA, ANNA	2010-10-12	2010-12-31
5.	SCOTT, JON	2010-02-01	2010-04-30
6.	STEVENSON, MICHAEL	2010-01-04	2010-04-23
7.	COOK, JONATHAN	2010-09-20	2010-12-31
8.	FORRER, THOMAS	2010-05-10	2010-08-27
9.	PINDER, ALEX-JASON	2010-09-07	2010-12-31
10.	ALDRED, LISA	2010-05-03	2010-09-03
11.	HIGGINS, JOHN	2010-08-30	2010-12-31
12.	LAOUTARIS, NICOLE	2010-08-30	2010-12-31
13.	BOVAIR, ANDREW	2010-05-03	2010-08-27
14.	CAPANO, MATTHEW	2010-05-03	2010-08-27
15.	PRIDHAM, CINDY	2010-05-03	2010-08-27
16.	DUVAL, YVAN	2010-01-01	2010-04-30
17.	RAMESH, PRAVEEN	2010-01-01	2010-04-30
18.	MARTIN, SHANE	2010-09-07	2010-12-31
19.	TOZZO, BRUNO	2010-04-26	2010-08-27
20.	WEILER, KELLY	2010-04-26	2010-08-27
21.	BEVERLEY, KEVIN	2010-05-03	2010-08-27
22.	WALKER, TAMMAGEN	2010-04-26	2010-08-23
23.	RICHARDS, TANYA	2010-08-26	2010-12-31
24.	HOWSE, KATHLEEN	2010-06-14	2010-10-15
25.	CORKE, DARRYL	2010-05-03	2010-09-03
26.	MADORE, WILLIAM	2010-05-03	2010-09-03
27.	REILLY, MICHAEL - Term 1	2010-01-01	2010-04-30
28.	REILLY, MICHAEL - Term 2	2010-05-01	2010-08-31
29.	REILLY, MICHAEL - Term 3	2010-09-01	2010-12-31
30.	DOUCET, ADAM - Term 1	2010-01-01	2010-04-30
31.	DOUCET, ADAM - Term 2	2010-05-01	2010-08-31
32.	DOUCET, ADAM - Term 3	2010-09-01	2010-12-31
33.	PATERSON, GREG - Term 1	2010-01-01	2010-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
34.	PATERSON, GREG - Term 2	2010-05-01	2010-08-31
35.	PATERSON, GREG - Term 3	2010-09-01	2010-12-31
36.	BEGGS, ADAM - Term 1	2010-01-01	2010-04-30
37.	BEGGS, ADAM - Term 2	2010-05-01	2010-08-31
38.	BEGGS, ADAM - Term 3	2010-09-01	2010-12-31

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) **450**	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	**F2** Eligible expenditures after March 26, 2009 (see note 1 below) **452**	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	**X** Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	**Y** Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	578	25.000 %		1
2.		10.000 %	620	25.000 %		1
3.		10.000 %	930	25.000 %		2
4.		10.000 %	5,856	25.000 %		11
5.		10.000 %	6,362	25.000 %		13
6.		10.000 %	7,066	25.000 %		16
7.		10.000 %	7,447	25.000 %		15
8.		10.000 %	7,953	25.000 %		16
9.		10.000 %	8,387	25.000 %		16
10.		10.000 %	8,965	25.000 %		18
11.		10.000 %	8,965	25.000 %		18
12.		10.000 %	8,965	25.000 %		18
13.		10.000 %	9,063	25.000 %		17
14.		10.000 %	9,063	25.000 %		17
15.		10.000 %	9,063	25.000 %		17
16.		10.000 %	9,274	25.000 %		17
17.		10.000 %	9,274	25.000 %		17
18.		10.000 %	9,544	25.000 %		16
19.		10.000 %	9,605	25.000 %		18
20.		10.000 %	9,605	25.000 %		18
21.		10.000 %	9,689	25.000 %		17
22.		10.000 %	9,873	25.000 %		17
23.		10.000 %	9,893	25.000 %		18
24.		10.000 %	10,202	25.000 %		18
25.		10.000 %	10,246	25.000 %		18
26.		10.000 %	10,246	25.000 %		18
27.		10.000 %	10,010	25.000 %		17
28.		10.000 %	10,010	25.000 %		17
29.		10.000 %	10,010	25.000 %		17
30.		10.000 %	10,725	25.000 %		17
31.		10.000 %	10,725	25.000 %		17
32.		10.000 %	10,725	25.000 %		17
33.		10.000 %	10,725	25.000 %		17
34.		10.000 %	10,725	25.000 %		17
35.		10.000 %	10,725	25.000 %		17
36.		10.000 %	11,440	25.000 %		17
37.		10.000 %	11,440	25.000 %		17
38.		10.000 %	11,440	25.000 %		17

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) **460**	**H** Maximum CETC per WP (see note 3 below) **462**	**I** CETC on eligible expenditures (column G or H, whichever is less) **470**	**J** CETC on repayment of government assistance (see note 4 below) **480**	**K** CETC for each WP (column I or column J) **490**
1.	145	3,000	145		145
2.	155	3,000	155		155
3.	233	3,000	233		233
4.	1,464	3,000	1,464		1,464
5.	1,591	3,000	1,591		1,591
6.	1,767	3,000	1,767		1,767

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
7.	1,862	3,000	1,862		1,862
8.	1,988	3,000	1,988		1,988
9.	2,097	3,000	2,097		2,097
10.	2,241	3,000	2,241		2,241
11.	2,241	3,000	2,241		2,241
12.	2,241	3,000	2,241		2,241
13.	2,266	3,000	2,266		2,266
14.	2,266	3,000	2,266		2,266
15.	2,266	3,000	2,266		2,266
16.	2,319	3,000	2,319		2,319
17.	2,319	3,000	2,319		2,319
18.	2,386	3,000	2,386		2,386
19.	2,401	3,000	2,401		2,401
20.	2,401	3,000	2,401		2,401
21.	2,422	3,000	2,422		2,422
22.	2,468	3,000	2,468		2,468
23.	2,473	3,000	2,473		2,473
24.	2,551	3,000	2,551		2,551
25.	2,562	3,000	2,562		2,562
26.	2,562	3,000	2,562		2,562
27.	2,503	3,000	2,503		2,503
28.	2,503	3,000	2,503		2,503
29.	2,503	3,000	2,503		2,503
30.	2,681	3,000	2,681		2,681
31.	2,681	3,000	2,681		2,681
32.	2,681	3,000	2,681		2,681
33.	2,681	3,000	2,681		2,681
34.	2,681	3,000	2,681		2,681
35.	2,681	3,000	2,681		2,681
36.	2,860	3,000	2,860		2,860
37.	2,860	3,000	2,860		2,860
38.	2,860	3,000	2,860		2,860

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2010-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information LUCY LOMBARDI	**120** Telephone number including area code (905) 532-4648

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes ☐ 2 No ☒

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ____________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 8,767,651

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \textbf{ minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \textbf{ minus } 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	HOLMES, CORY
2.	434a	Powerline Technician	WILMOT, MICHAEL
3.	434a	Powerline Technician	HAGAN, CHRISTOPHER
4.	434a	Powerline Technician	WALSH, RYAN
5.	434a	Powerline Technician	SIMPSON, CHRISTOPHER
6.	434a	Powerline Technician	CHARD, ROBERT
7.	434a	Powerline Technician	ROBINSON, STEVEN
8.	434a	Powerline Technician	COUSINS, MATTHEW
9.	434a	Powerline Technician	MAAS, ADAM
10.	434a	Powerline Technician	LONG, JEFF
11.	434a	Powerline Technician	LAMB, TIM
12.	434a	Powerline Technician	WALSH, ADAM
13.	434a	Powerline Technician	FERGUSON, ANDREW
14.	434a	Powerline Technician	JOHNSTON, BOB
15.	434a	Powerline Technician	WHITE, DARRYL
16.	434a	Powerline Technician	FLYNN, ANDREW
17.	434a	Powerline Technician	FOSTER, JORDAN
18.	434a	Powerline Technician	SHINN, JUSTIN
19.	434a	Powerline Technician	GRAY, ROBERT

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	15005	2006-02-27	2010-01-01	2010-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
2.	15004	2006-02-27		
3.	15002	2006-02-27		
4.	15003	2006-02-27		
5.	15006	2006-02-27		
6.	15007	2006-02-27		
7.	23972	2007-06-07		
8.	23969	2007-06-07		
9.	23971	2007-06-07		
10.	23970	2007-06-07		
11.	23973	2007-06-07		
12.	PC9094	2009-09-28		
13.	PA4127	2009-09-28		
14.	PC9201	2009-09-28		
15.	PC9203	2009-09-28		
16.	PC9095	2009-09-28		
17.	PC9093	2009-09-28		
18.	PC9202	2009-09-28		
19.	PC9096	2009-09-28		

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		58	58	1,589
2.		58	58	1,589
3.		58	58	1,589
4.		58	58	1,589
5.		58	58	1,589
6.		58	58	1,589
7.		365	365	10,000
8.		284	284	7,781
9.		365	365	10,000
10.		365	365	10,000
11.		365	365	10,000
12.		365	365	10,000
13.		365	365	10,000
14.		365	365	10,000
15.		365	365	10,000
16.		365	365	10,000
17.		365	365	10,000
18.		365	365	10,000
19.		365	365	10,000

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		75,254	75,254	26,339
2.		75,254	75,254	26,339
3.		75,254	75,254	26,339
4.		75,254	75,254	26,339
5.		75,254	75,254	26,339
6.		75,254	75,254	26,339
7.		68,536	68,536	23,988
8.		53,327	53,327	18,664
9.		68,536	68,536	23,988
10.		68,536	68,536	23,988
11.		68,536	68,536	23,988
12.		58,846	58,846	20,596
13.		58,846	58,846	20,596
14.		58,846	58,846	20,596
15.		58,846	58,846	20,596
16.		58,846	58,846	20,596
17.		58,846	58,846	20,596
18.		58,846	58,846	20,596
19.		58,846	58,846	20,596

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	1,589		1,589
2.	1,589		1,589
3.	1,589		1,589
4.	1,589		1,589
5.	1,589		1,589
6.	1,589		1,589
7.	10,000		10,000
8.	7,781		7,781
9.	10,000		10,000
10.	10,000		10,000
11.	10,000		10,000
12.	10,000		10,000
13.	10,000		10,000
14.	10,000		10,000
15.	10,000		10,000
16.	10,000		10,000
17.	10,000		10,000
18.	10,000		10,000
19.	10,000		10,000

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 137,315 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ____________ x percentage on line 170 in Part 1 ________ % = ... ____________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.

For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.

For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . POWERSTREAM INC.

Taxation Year . . . . 2010-01-01 to 2010-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	☒	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . N

Corporation is related . . . . N

Number of associated corporations . . .

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* 505,236

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		32,813,266
Taxable income		32,636,831
Donations		176,435
Calculation of income from an active business carried on in Canada		32,813,266
Dividends paid		10,532,000
Dividends paid – Regular	10,532,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		89,402,400
Balance of the general rate income pool at the end of the year		111,921,813
Part I tax (base amount)		12,401,996

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	5,333,992	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	9,246,731
Investment tax credits	540,638	Other*		Surtax credit	
Abatement/Other*	6,527,366	Provincial or territorial tax	4,417,975	Other*	

Balance due/refund (–) 505,236

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Capital dividend amount	2,587,166
Cumulative eligible capital	7,117,982
Financial statement reserve	17,233,493

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	32,813,266		
Taxable income	32,636,831		
% Allocation	100.00		
Attributed taxable income	32,636,831		
Surtax	39,979	N/A	N/A
Tax payable before deduction*	4,240,109		
Deductions and credits	184,750		
Net tax payable	4,095,338		
Attributed taxable capital	746,094,157		N/A
Capital tax payable**	543,814		N/A
Total tax payable***	4,639,152		
Instalments and refundable credits	221,177		
Balance due/Refund (-)	4,417,975		

* For Québec, this includes special taxes and logging operations.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
POWERSTREAM INC.	746,094,157	747,642,639	746,094,157	746,094,157
Total	746,094,157	747,642,639	746,094,157	746,094,157

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
POWERSTREAM INC.		746,094,157	747,642,639
Total		746,094,157	747,642,639

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2010-12-31**	**2009-12-31**	**2008-12-31**	**2007-12-31**	**2006-12-31**
Net income	32,813,266	25,815,627	20,170,245	35,400,459	31,432,728
Taxable income	32,636,831	25,556,717	18,142,389	35,294,289	31,384,069
Active business income	32,813,266	25,815,627	20,170,245	33,235,180	31,121,818
Dividends paid	10,532,000	31,082,643	8,513,868	4,736,400	6,555,000
Dividends paid – Regular	10,532,000				
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	89,402,400	72,023,832	59,687,007	37,159,280	
GRIP – end of the year	111,921,813	89,402,400	72,023,832	59,687,007	37,159,280
Donations	176,435	258,910	2,027,856	106,170	48,659
Balance due/refund (-)	505,236	-758,019			

Federal taxes

Part I before surtax	5,333,992	4,343,215	3,537,766	7,415,086	11,925,946
Surtax				395,296	351,502
Part I.3					
Part IV					
Part I & Surtax	5,333,992	4,343,215	3,537,766	7,810,382	6,983,997
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution				558	650
Investment tax credit	540,638	512,560		292,078	
Abatement/other*	6,527,366	4,855,777	3,356,342	5,848,460	5,313,528

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

ITC refund					
Dividend refund				577,408	113,837
Instalments	9,246,731	10,026,123	3,537,766	7,232,974	6,870,160
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2010-12-31	2009-12-31	2008-12-31	2007-12-31	2006-12-31
Net income	32,813,266	25,815,627	19,878,167	35,091,498	
Taxable income	32,636,831	25,556,717	17,850,311	34,985,328	
% Allocation	100.00	100.00	100.00	100.00	
Attributed taxable income	32,636,831	25,556,717	17,850,311	34,985,328	31,354,156
Surtax	39,979	42,500	42,500	34,000	34,000
Income tax payable before deduction	4,240,109	3,577,940	2,499,044	4,897,946	4,389,582
Income tax deductions /credits	184,750	181,957	128,433	121,916	70,108
Net income tax payable	4,095,338	3,438,483	2,413,111	4,810,030	4,353,474
Taxable capital	746,094,157	747,642,639	585,300,617	535,601,747	496,012,385
Capital tax payable	543,814	1,648,446	1,283,176	1,490,840	1,458,037
Total tax payable*	4,639,152	5,086,929	3,696,287	6,300,870	5,811,511
Instalments and refundable credits	221,177	162,040	9,716,625	6,933,283	5,490,913
Balance due/refund**	4,417,975	4,924,889	-6,020,338	-632,413	320,598

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2011-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2011-01-31	831,096			831,096
2011-02-28	831,096			831,096
2011-03-31	831,096			831,096
2011-04-30	831,096			831,096
2011-05-31	831,096			831,096
2011-06-30	831,096			831,096
2011-07-31	831,096			831,096
2011-08-31	831,096			831,096
2011-09-30	831,096			831,096
2011-10-31	831,096			831,096
2011-11-30	831,096			831,096
2011-12-31	831,088			831,088
Total	9,973,144			9,973,144

Canada Revenue Agency / Agence du revenu du Canada

Code 1101

SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) EXPENDITURES CLAIM

Use this form:
- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:
- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant
POWERSTREAM INC.

Enter one of the following:
85750 3346 RC0002
Business Number (BN)

Tax year
From: 2010-01-01 (Year Month Day)
To: 2010-12-31 (Year Month Day)

Social Insurance Number (SIN)

050 Total number of projects you are claiming this tax year:
7

100 Contact person for the financial information LUCY LOMBARDI	**105** Telephone number/extension (905) 532-4648	**110** Fax number
115 Contact person for the technical information LUCY LOMBARDI	**120** Telephone number/extension (905) 532-4648	**125** Fax number

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Name of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)
See schedule

Part 3 – Calculation of SR&ED expenditures

What did you spend on your SR&ED projects?

Section A – Select the method to calculate the SR&ED expenditures

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for this tax year.
I understand that my election is irrevocable (cannot be changed) for this tax year.

160 ☒ I elect to use the proxy method
(Enter "0" on line 360. Complete Part 5 and you do not need to track any expenditure incurred for overhead)

162 ☐ I choose to use the traditional method
(Enter "0" on line 355. Complete line 360, and track any expenditure incurred for overhead)

Section B – Calculation of allowable SR&ED expenditures (to the nearest dollar)

• SR&ED portion of salary or wages of employees directly engaged in the SR&ED:			
a) Employees other than specified employees for work performed in Canada	**300**	+	968,629
b) Specified employees for work performed in Canada	**305**	+	
Subtotal (add lines 300 and 305)	**306**	=	968,629
c) Employees other than specified employees for work performed outside Canada (subject to limitations – see guide)	**307**	+	
d) Specified employees for work performed outside Canada (subject to limitations – see guide)	**309**	+	
• Salary or wages identified on line 315 in prior years that were paid in this tax year	**310**	+	
• Salary or wages incurred in the year but not paid within 180 days of the tax year end **315**			
• Cost of materials consumed in performing SR&ED	**320**	+	
• Cost of materials transformed in performing SR&ED	**325**	+	
• Contract expenditures for SR&ED performed on your behalf:			
a) Arm's length contracts	**340**	+	1,284,880
b) Non-arm's length contracts	**345**	+	
• Lease costs of equipment used:			
a) All or substantially all (90% of the time or more) for SR&ED	**350**	+	
b) Primarily (more than 50% of the time but less than 90%) for SR&ED. (Enter 50% of lease costs if you use the proxy method or enter "0" if you use the traditional method)	**355**	+	
• Overhead and other expenditures (enter "0" if you use the proxy method)	**360**	+	
• Third-party payments (complete Form T1263*)	**370**	+	
Total current SR&ED expenditures (add lines 306 to 370; do not add line 315) (Corporations need to adjust line 118 of schedule T2SCH1)	**380**	=	2,253,509
• **Capital Expenditures** (see guide for what qualifies for SR&ED) (Do not include these capital expenditures on schedule T2SCH8)	**390**	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	**400**	=	2,253,509

Section C – Calculation of pool of deductible SR&ED expenditures (to the nearest dollar)

Amount from line 400	**420**		2,253,509
Deduct			
• provincial government assistance for expenditures included on line 400	**429**	–	101,408
• other government assistance for expenditures included on line 400	**431**	–	
• non-government assistance for expenditures included on line 400	**432**	–	
• SR&ED ITCs applied and/or refunded in the prior year (see guide)	**435**	–	512,560
• sale of SR&ED capital assets and other deductions	**440**	–	
Subtotal (line 420 minus lines 429 to 440)	**442**	=	1,639,541
Add			
• repayments of government and non-government assistance that previously reduced the SR&ED expenditure pool	**445**	+	
• prior year's pool balance of deductible SR&ED expenditures (from line 470 of prior year T661)	**450**	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	**452**	+	
• amount of SR&ED ITC recaptured in the prior year	**453**	+	
Amount available for deduction (add lines 442 to 453) (enter positive amount only, include negative amount in income)	**455**	=	1,639,541
• Deduction claimed in the year (Corporations should enter this amount on line 411 of schedule T2SCH1)	**460**	–	1,639,541
Pool balance of deductible SR&ED expenditures to be carried forward to future years (line 455 minus 460)	**470**	=	

* Form T1263, *Third-Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 4 – Calculation of qualified SR&ED expenditures for investment tax credit (ITC) purposes

The resulting amount is used to calculate your refundable and/or non refundable ITC.

Enter the breakdown between current and capital expenditures (to the nearest dollar)

		Current Expenditures		Capital Expenditures
Total expenditures for SR&ED (from line 380 and 390)	492	2,253,509	496	
Add				
• payment of prior years' unpaid amounts (other than salary or wages)	500 +			
• prescribed proxy amount (complete Part 5) (Enter "0" if you use the traditional method)	502 +	577,059		
• expenditures on shared-use equipment (see guide)			504 +	
• qualified expenditures transferred to you (complete Form T1146**)	508 +		510 +	
Subtotal (add lines 492 to 508, and add lines 496 to 510)	511 =	2,830,568	512 =	
Deduct				
• provincial government assistance	513 –	127,376	514 –	
• other government assistance	515 –		516 –	
• non-government assistance and contract payments	517 –		518 –	
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	520 –			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	528 –			
• prescribed expenditures not allowed by regulations (see guide)	530 –		532 –	
• other deductions (see guide)	533 –		535 –	
• non-arm's length transactions				
– assistance allocated to you (complete Form T1145*)	538 –		540 –	
– expenditures for non-arm's length SR&ED contracts (from line 345)	541 –			
– adjustments to purchases (limited to costs) of goods and services from non-arm's length suppliers (see guide)	542 –		543 –	
– qualified expenditures you transferred (complete Form T1146**)	544 –		546 –	
Subtotal (line 511 minus lines 513 to 544 and line 512 minus lines 514 to 546)	557 =	2,703,192	558 =	
Qualified SR&ED expenditures (add lines 557 and 558)			559 =	2,703,192
Add				
• repayments of assistance and contract payments made in the year			560 +	
Total qualified SR&ED expenditures for ITC purposes (add lines 559 and 560)			570 =	2,703,192

* Form T1145, *Agreement to Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement to Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

Part 5 – Calculation of prescribed proxy amount (PPA)

A notional amount representing your overhead and other expenditures.

This part calculates the PPA to enter on line 502 in Part 4. Do not complete this part if you have chosen to use the traditional method in Part 3 (line 162).
You can only claim a PPA if you elected to use the proxy method for the year in Part 3 (line 160).

Special rules apply for specified employees. Calculate your salary base in Section A and the PPA in section B.

Section A – Salary base

Salary or wages of employees other than specified employees (from line 300 and 307) . . . . . **810** + 968,629

Deduct

Bonuses, remuneration based on profits, and taxable benefits that were included on line 810 . . . . . **812** – 80,846

Subtotal (line 810 minus 812) . . . . . **814** = 887,783

Salary or wages of specified employees

850	852	854	856	858	860
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**	**Column 6**
Name of Specified Employee	Total salary or wages for the year (SR&ED and non-SR&ED) excluding bonuses, remuneration based on profits, and taxable benefits (to the nearest dollar)	% of time spent on SR&ED (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	2,5 x A x B/365 A = Year's maximum pensionable earnings B = Number of days employed in tax year	Amount in column 4 or 5, whichever amount is less

(Enter total of column 6 on line 816) **816** +

Salary base (total of lines 814 and 816) . . . . . **818** = 887,783

Section B – Prescribed proxy amount (PPA)

Enter 65% of the salary base (line 818 x 65%) . . . . . **820** = 577,059

Enter the amount from line 820 on line 502 in Part 4 unless the overall cap on PPA applies to you. . . . . .

(See the guide for explanation and example of the overall cap on PPA)

Part 6 – Project costs

Information requested in this part must be provided for **all** SR&ED projects claimed in the year.
Expenditures should be recorded and allocated on a project basis.

750	752	754	756
Project title or identification code	Salary or wages in the tax year (Total of lines 306 to 309)	Cost of materials in the tax year (Total of lines 320 and 325)	Contract expenditures for SR&ED performed on your behalf in the tax year (Total of lines 340 and 345)
1. 2010 P1: System assets, equipment & apparatus improveme	96,293		182,997
2. 2010 P2: Power transformer stations and DG connection fac	170,791		299,561
3. 2010 P3: Electric Power Distribution System – Technical stra	178,666		148,217
4. 2010 P4: Smart metering and PSI facility energy conservatio	74,125		393,529
5. 2010 P5: Outage Management System development and ope	119,803		52,959
6. 2010 P6: Smart Grid initiatives development	211,708		114,610
7. 2010 P7: Sustainable generation	117,243		93,007
Total	968,629		1,284,880

Part 7 – Additional information

Expenditures for SR&ED performed by you in Canada (line 400 minus lines 307, 309, 340, 345, and 370) **605** 968,629

From the total you entered on line 605, estimate the percentage of distribution of the sources of funds for SR&ED performed within your organization.

		Canadian (%)		Foreign (%)
Internal	600	100.000		
Parent companies, subsidiaries, and affiliated companies	602		604	
Federal grants (do not include funds or tax credits from SR&ED tax incentives)	606			
Federal contracts	608			
Provincial funding	610			
SR&ED contract work performed for other companies on their behalf	612		614	
Other funding (e.g., universities, foreign governments)	616		618	

Enter the number of SR&ED personnel in full-time equivalents (FTE):

Scientists and engineers	632	7
Technologists and technicians	634	
Managers and administrators	636	
Other technical supporting staff	638	

Part 8 – Claim checklist

To ensure your claim is complete, make sure you have:

1. used the current version of this form . . . ☒
2. entered the method you have chosen for reporting your SR&ED expenditures in Section A of Part 3 . . . ☒
3. completed Part 2 for each project . . . ☒
4. filed a completed Schedule T2SCH31 or Form T2038(IND) to claim ITCs on your qualified SR&ED expenditures . . . ☒
5. filed a completed Form T1145*, T1146**, T1174*** and/or T1263**** including any required attachments, if applicable . . . ☐

To expedite the processing of your claim, make sure you have:

1. completed Form T2, *Corporation Income Tax Return* or Form T1, *Income Tax and Benefit Return* . . . ☒
2. filed the appropriate provincial and/or territorial tax credit forms, if applicable . . . ☒
3. retained documents to support the SR&ED expenditures you claimed . . . ☒
4. checked boxes 231 and 232 on page 2 of your T2 return to indicate attachment of Form T661 and Schedule T2SCH31 . . . ☒

* Form T1145, *Agreement ta Allocate Assistance for SR&ED Between Persons Not Dealing at Arm's Length*

** Form T1146, *Agreement ta Transfer Qualified Expenditures Incurred in Respect of SR&ED Contracts Between Persons Not Dealing at Arm's Length*

*** Form T1174, *Agreement Between Associated Corporations to Allocate Salary or Wages of Specified Employees for Scientific Research and Experimental Development (SR&ED)*

**** Form T1263, *Third·Party Payments for Scientific Research and Experimental Development (SR&ED)*

Part 9 – Certification

I certify that I have examined the information provided on this form and on the attachments and it is true, correct, and complete.

165 LUCY LOMBARDI
Name of authorized signing officer of the corporation, or individual

Signature

170
Date

175 Deloitte & Touche LLP
Name of person/firm who completed this form

Part 2 - Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P1: System assets, equipment & apparatus improvement

202 Project start date: 2007-01 (Year Month)

204 Completion or expected completion date: 2011-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project   **210** 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes   2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory   **226** 1 ☒ In a commercial plant or facility

224 1 ☐ In a dedicated research facility   **228** 1 ☒ Others, specify   **229** At field sites

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☒
The improvement of existing	**237** 1 ☒	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

PSI sought to acquire the knowledge and knowhow to create one set of merged standards and materials specifications (SMS) for its entire service area to replace the two existing sets in use, one each for the north and south areas. The existing sets reflected different design details and construction

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

practices, which needed to be reconciled in the process of creating a single set of SMS. It would likely include a mix of elements from the existing sets as well as new individual SMS which would replace the relevant items in both of the existing sets. PSI also sought to find out the extent to which the concepts of standardization could be applied in the creation of a single set of SMS to reduce the proliferation of components and materials that are required to maintain its existing system and to design and build system upgrades and additions. Efforts to standardize SMS and use modular construction methods need, of course, to meet all technical, safety and operating requirements and should, when properly applied, lead to more cost effective asset management from leveraging PSI s purchasing power.

In addition, PSI has to increase and deepen its existing understanding of the causes of failures with items in service like overhead switches, solid dielectric (SD) switchgear, transformers of all types, and PDH switchgear, so that (1) its specifications can be used with assurance to acquire new items of these types whose failure rate in service approaches zero, (2) its construction engineering standards can be improved and made more robust, e.g. its O/H system hardened, so that the probability of the occurrence of similar failures in future is minimized to the extent practical, and (3) alternative technical solution options for systemic failure issues can be developed. A related subsidiary advance is better capability to (a) create engineering equipment specifications and installation designs for items that have passed field acceptance trails, and (b) undertake preliminary investigations of new items with potential for inclusion in field trials.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The obstacles to merging two distinct sets of SMS into a single state-of-the-art one the methodology and techniques to do so and how to reconcile different technical approaches that might have been taken in the same areas that the new single integrated set of SMS has to cover. Other subsidiary issues are the extent to which existing information systems can be interfaced, how obsolescence should be handled, what the review and approval process should entail, and how much weight should be given to the consequences of implementing a new specific SMS when it is under development. Similar challenges exist with standardization efforts to reduce item and materials proliferation.

When an in-service item fails, it is important that the appropriate level of investigative effort and analysis is undertaken to determine why the item failed and how similar types of failures can be prevented in future. Very often such work is undertaken with representatives of the supplier or manufacturer of the failed items. Typically too, other LDC experience is accessed where appropriate as such input often provides additional perspectives on a specific incident that is being investigated, especially when forensic examination yields limited clues to possible causes due to the extent of the damage involved. Suppliers to the electric power distribution industry sector develop new items and components, which they hope will become industry-approved standard items. Because an item/component is used successfully by one LDC, it does not automatically mean that it will do the same in a similar application for other LDCs. Differences in distribution system characteristics, operations and maintenance practices, as well as environmental conditions may have an impact on the outcome. PSI experience has shown that it needs to both conduct a detailed technical review of the new item/component s design characteristics, and a successful field trial before any new item/component is accepted as a standard part for use in new construction and existing asset maintenance.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

During the year, a 3-person subcontractor team was formed to merge the prevailing sets of SMS that were in use in the north and south areas respectively. The intent was to review, merge and produce one set of SMS. A methodology was developed to undertake these activities and defined the approval process for each individual merged SMS s release. Its development included the revision or creation of 4 procedures, e.g. New Equipment/Materials Review and Approvals, and Material Specifications & Construction Standards Internal Review and Approval Process. In addition, another subcontractor created code to facilitate the migration and merger of the materials standards and stock codes that the north area was using into the PSI JDE based system. By year end, just more than a third of the merged SMS (73 standards, 83 specifications) had been covered and released. Much iteration was involved in some areas, e.g. for guys & anchors from which 47 transformed into 9 new SMS. Piloting of the merged SMS was started with Inspections and Locates personnel.

Revised terms of reference were established for PSI s Standards Committee (SC), which met 6 times during 2010. The SC dealt with 5 action items carried over from 2009 and generated 20 new action items. Six action items were carried over to 2011. Items addressed in standardization efforts that the SC endorsed were: (1) Tap wedge connectors and tools, (2) Primary underground cables, i.e. aluminum conductor for 1/0 and 750 MCM primary and all secondary cables, (3) Guying standards and practices, (4) WRC wood poles, sizes, and classes, (5) Fibreglass guy rod sizes, and (6) Single phase overhead polemount transformers KVA ratings. Three other items resolved were: (a) Adding H0 bushings for 3000KVA and 5000KVA transformers and revising all the relevant technical documentation, (b) Specifying dual wall PVC or FRE ducts for communication cables in trenches following a communication duct collapse, and (c) Replacing the existing strand vise with a higher strength 16,000lbs automatic model.

Miscellaneous other new or revised SMS were prepared and issued for review and approval. Two examples are a bollard material specification and the associated standards, and a new material specification for single phase submersible transformers. Reviews and approvals were also carried out of transformer test reports, shop drawings and subdivision packages.

Five failure analysis investigations were undertaken during the year with the assistance of the suppliers, as necessary. The items involved were two models of overhead switches, SD switchgear, single phase padmount transformers, and PMH switchgear. Overhead switches now obsolete of mid-to late 1990 s vintage were failing. Investigations found hairline cracks in the porcelain insulator, potentially causing flashovers leading to power outages, adjacent equipment damage, and a switch operation safety hazard. In one failure, separation occurred, depositing debris on the vehicle below, but without personal injury. Analysis suggested the possible cause was associated with the adhesion between the pin/stud and the porcelain insulator connection, with moisture ingress and freezing also potentially contributing. Following internal review, replacement of all 380 switches was approved. The nine SD switchgear items in service were failing after about a year. They were returned to the supplier for tests and failure analysis of the root cause(s). The supplier reported all failures were identical and occurred due to separation between the EPR and Epoxy sealant in the flexible bus inside the switch. Design modifications were made to eliminate the separation found. A modified unit with the new design of bus was installed for a field trial. A rusting tank top issue with one supplier s single phase padmount transformers (MY 2007) had to be investigated and was not resolved by year end. PMH switchgear 2004-8 vintage and SMD overhead switches from the same manufacture were failing. Investigations showed the former were due to a mini-rupter spring component issue and latter to broken insulators and bent brackets.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

59. With regard to potential new items, initial investigations were made into a
60. new MV switch, a cable system, cable pull software and helical anchors. A
61. field trial with a fibreglass crossarm was planned and an ad hoc group formed
62. to re-examine the use of RS poles.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

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4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
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4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project — **254** Name

255 1 ☐ Other employee of the company — **256** Name

257 1 ☒ External consultant — **258** Name Deloitte & Touche — **259** Firm Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Doug Fairchild	P.Eng., 21 years experience, Manager, Planning & Standards
2	Debbie Dadwani	P.Eng., 26 years experience, Distribution Standards Engineer
3	Alex Cestra	C.E.T. , 25 years experience, Engineering Technologist

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	MGA Consulting	89357 9367 RC0001
2	Roan International	10456 6062 RC0001
3	Rondinone Management Services	87834 5115 RC0001
4	Joe Crozier	86110 6631 RC0001
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What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 ☒ Project planning documents
271 1 ☒ Records of resources allocated to the project, time sheets
272 1 ☐ Design of experiments
273 1 ☒ Project records, laboratory notebooks
274 1 ☐ Design, system architecture and source code
275 1 ☒ Records of trial runs
276 1 ☒ Progress reports, minutes of project meetings
277 1 ☒ Test protocols, test data, analysis of test results, conclusions
278 1 ☐ Photographs and videos
279 1 ☐ Samples, prototypes, scrap or other artefacts
280 1 ☒ Contracts
281 1 ☒ Others, specify **282** Set of merged SMS completed to end of 2010

Part 2 - Project information (continued)

Project number **2**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P2: Power transformer stations and DG connection facili

202 Project start date
2007-01
Year Month

204 Completion or expected completion date
2011-12
Year Month

206 Field of science or technology code
(See guide for list of codes)
2.02.01 Electrical and electronic engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project **210** 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes 2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory
226 1 ☒ In a commercial plant or facility
224 1 ☐ In a dedicated research facility
228 1 ☒ Others, specify **229** At field sites

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☒
The improvement of existing	**237** 1 ☒	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. PSI wanted to advance its knowledge, know-how and capabilities:
2. 1. To create a power transformer station design with a configuration for the
3. next generation of Metering, Relay and Control (MRC) systems for the Markham
4. #4 Transformer Station (TS) that goes beyond what had been achieved previously

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

with the MRC improvements developed for the last power transformer station it had designed and commissioned

2. Of on-line condition monitoring of power transformers and whether or not the results from a pilot installation warrant incorporating such an approach into its standard practice for the O&M of all TS in service

3. For improved fault detection for a 44kV/13.8 transformer with a 3-wire/4-wire configuration

4. For methods and techniques to conduct connection impact assessments involved with the Feed-in-Tariff (FIT) Program for distributed generation and how distributed generation (DG) systems, 250kW upwards, can be remotely monitored and tripped

5. To implement a super-highway for high priority systems data communications, and

6. To understand why all failures to, and malfunctions of TS equipment and systems have occurred, and the modifications that have to be implemented to eliminate the possibility of the same and similar incidents re-occurring.

To make the advances it sought, PSI planned to use specialist subcontractors/industry suppliers with power transformer specific design experience. While PSI s expertise is in TS operation and maintenance, it would do likewise in this area, whenever required, if extensive analysis or specialized equipment knowledge would contribute to a better understanding of why an incident occurred and how the re-occurrence of similar incidents could be prevented.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

PSI had made improvements to its power TS designs in the past, particularly with the MRC systems aspects and integrating linkages to its SCADA system.

The obstacle faced with designing its MTS #4 was whether or not the features of its design s electronic protection systems different from those in earlier stations will perform better than the systems in service with MTS #3 and for the Greenwood TS expansion. Design completion and testing/commissioning trials still had to be performed. The same applied to a new 44kV/13.8kV TS with a 3-wire/4-wire configuration.

Failure/malfunction prevention is pursued in three generic ways. Design reviews and pre-acceptance testing to specific criteria are requested along with in-service warranties with equipment acquisition. Once in service the supplier s recommended maintenance policy & actions are followed, and evolve with operating experience. Finally, condition monitoring techniques are used and attempts made to correlate condition or performance deterioration with the risk of an incident occurring. Testing the insulating fluids in transformers and switchgear is one example. However, the degree of predictability between the condition/properties/ performance degradation that is monitored, and an incident occurring is open to question.

Facilitating the connection of DG systems to its network is a mandated responsibility for PSI. In the process of doing so, it must ensure its network is capable of handling these supply sources in a safe and stable manner without also exposing the DG equipment to any risk of damage caused by faults and other incidents on its network.

The design configuration for a data communications super-highway still has to be finalized.

For PSI, incidents of failure and malfunction of TS equipment have historically happened infrequently. The consequence can be very serious in terms of equipment damage, of service outages and to personnel safety. To determine why they have happened, investigations are launched with contributions from equipment suppliers, other LDC s, and specialist subcontractors. Despite these efforts, forensic investigations sometimes

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

conclude that the incident occurred for indeterminate reasons.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

The design development of Markham Transformer Station (MTS) #4 was carried over from 2009. For this year, as in prior years, the activities involved were performed by three subcontractors   one for the 3rd party commissioning effort   under the direction of PSI staff. The focus for the year was on completing the design of the electronic protection systems to comply with PSI s scope of work and design concepts, and carrying out the necessary testing and trials to commission and energize the new station. Because of the protection and control systems re-design that was started last year to meet PSI requirements, specific attention would be paid to ensuring all trials and testing were performed satisfactorily with acceptable results. The electronic protection systems were simpler, as fewer components and wiring were involved, and also were more capable than the designs implemented for MTS#3 and also the Greenwood TS expansion. MTS #4 also had a better local interface design with PSI s SCADA system with a new approach from that used in the stations named. The commissioning process took longer than anticipated because of the custom designed bus protection with its unique logic design and custom programming - for which iterations were required - and P&C system integration with PSI s communications network. Once all testing had been completed, MTS #4 was first energized in August.

The on-line monitoring of individual power transformer condition, e.g. for temperature, 3 key gases and a moisture alarm, continued from last year on a pilot basis at MTS#3 using PSI s SCADA system. The results from the pilot were good and analysis of the data collected was used to determine maintenance action timing in place of the former fixed schedule approach. A decision was made to proceed with implementing the same condition monitoring approach at all TS, including the new MTS #4.

The new municipal substation in the north area, whose design was completed last year with subcontractor assistance, was brought into service without any issues arising. One new capability introduced into its integrated control arrangement for its 44kV 3-wire to 13.8kV 4-wire configuration was a newly created & tested sub-routine to check if any fuses had blown on the 44kV side.

Following the launch of the OPA s FIT and micro-FIT Programs in late 2009 to promote the implementation of DG units and systems, PSI had to develop its methodology to review the applications made for its service area and conduct connection impact assessments to ensure that PSI network could accommodate the DG and that the appropriate protection, metering and control arrangements were embedded in the applications that proceeded to implementation. In addition, PSI wanted to monitor all systems with a capacity of 250kW or greater for stability and system control reasons. With assistance from two subcontractors, PSI developed a design configuration incorporating 1.8GHz WiMax technology for FIT Generator remote tripping and monitoring. Proof of concept testing was stared and still in progress at the end of the year using the PSI location at 55 Patterson Road in Barrie to implement functions for remote trip & generator end open, for generator status and output monitoring. The PSI Solar PV system in Barrie would be one of the first sites in 2011 where FIT generator monitoring would be implemented.

Initial consideration was given in 2009 to enhancing PSI s communications infrastructure   a Proprietary Synchronous Optical Network (SONet) Ring   used as the data highway between PSI s key facilities and its SCADA servers by implementing a Gigabyte Ethernet Ring to act as a superhighway for high priority system data. These efforts were continued in 2010 and two rings were built, one for SCADA and one for PSI corporate communications. They were not in service at the end of the year as acceptance testing and trials still had

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

to be completed. One failure had to be investigated during the year with assistance from a specialist contractor. It was of a transformer tank at Cockburn station in a 44kv unit. The analysis showed it was due to a design flaw that required modifications made at the site to fix.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project — **254** Name

255 1 ☐ Other employee of the company — **256** Name

257 1 ☒ External consultant — **258** Name: Deloitte & Touche — **259** Firm: Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Glenn Allen	D.Sc., P. Eng., 28 years' experience, Mgr, Stn Design & Constr.
2	Gerry Reesor	P. Eng., 18 years' experience, Stations Engineer
3	Dave Burns	P. Eng., 11 years' experience, Project Engineer

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	A.G. Carlos	81367 6947 RC0001
2	K-Tek Electro Services Ltd	10288 9789 RC0001
3	RuggedCom	89421 4311 RC0001
4	SNC-Lavalin	86134 2913 RC0001
5	7528973 Canada Inc.	81641 0062 RC0001
6	T. & W. Info-Systems	86134 2913 RC0001
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10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270	1	☒	Project planning documents	**276**	1	☒	Progress reports, minutes of project meetings
271	1	☒	Records of resources allocated to the project, time sheets	**277**	1	☒	Test protocols, test data, analysis of test results, conclusions
272	1	☐	Design of experiments	**278**	1	☐	Photographs and videos
273	1	☒	Project records, laboratory notebooks	**279**	1	☐	Samples, prototypes, scrap or other artefacts
274	1	☐	Design, system architecture and source code	**280**	1	☒	Contracts
275	1	☒	Records of trial runs	**281**	1	☒	Others, specify **282** FIT Generator Monitoring – The PowerStream Solution

Part 2 - Project information (continued)

Project number **3**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P3: Electric Power Distribution System – Technical stra

202 Project start date: 2007-01 (Year Month)

204 Completion or expected completion date: 2011-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project   **210** 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes   2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory   **226** 1 ☒ In a commercial plant or facility

224 1 ☐ In a dedicated research facility   **228** 1 ☒ Others, specify **229** At field sites

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☒
The improvement of existing	**237** 1 ☐	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. The advancements sought were:
2. (1) The knowledge to make further enhancements - to an existing asset
3. management & condition assessment methodology - whose application will improve
4. PSI s ability to sustain the performance of all classes of assets in its

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

distribution network, (2) A means to incorporate the impacts of distributed generation (DG) of all kinds, but primarily gas, wind and solar within PSI s system planning practices, (3) A way to integrate GIS data with system planning software tools so that current models of the system can readily be created for system configuration improvement and other purposes, (4) Increased understanding of current loading imbalances on transformers and feeders and the need for system reconfiguration, particularly in the south service area, and of the likely future technical evolution of PSI s distribution network, for example with respect to load growth and the implications for more transformation capacity, (5) More comprehensive understanding of PSI s network performance in all respects, e.g. losses, reliability, etc., and the effective measures that could be developed and implemented through a detailed plan that will result in measurable improvements in performance, and (6) The knowledge and know how to create and implement further enhancements to S/W tools and processes for facilities management, including preparing engineering design drawings for distribution system network additions & modifications, and exporting such design data.

To make the advances listed, PSI planned to use its internal staff complemented by specialist engineering consultants and industry suppliers with appropriate specific experience as it had in prior years. It would have to work with them on a joint basis to carry out the necessary & essential design and development activities that had to be performed.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

Going into 2010, PSI had a formal methodology to support the technical management of its network assets, but its use in 2009 was unsatisfactory. The models used in the north and south areas needed to be merged, failure data had to be updated, better projections of impacts and additional decision support modules were all needed. PSI builds new capacity additions to its network when required, but if DG is located near loads, the requirements are reduced. With the launch of OPA s FIT and micro-FIT programs, DG connections were expected to increase significantly. However, PSI s past practice had been to treat connection applications on a case-by-case basis. Such an approach was inadequate to handle the aggregate impacts on PSI s network. Consideration of DG had therefore to be embedded within PSI s system planning. PSI uses S/W tools to model its network and run simulations of potential changes to it, e.g. to accommodate new loads and investigate what improvements might be made to improve performance. The base model and the proposed changes have traditionally been handled manually in a very time consuming input process for the simulation tool. PSI needed a way of electronically transferring the constantly updated model in its GIS system into its system planning tools. It also knew from experience in 2009 - when overloading some network components occurred - and from the introduction of new transformation capacity in 2010 that it had to investigate a reconfiguration of its south area system. The OEB is charged with ensuring LDCs focus on improving their network reliability, and expects LDCs like PSI to report its progress. Such progress can only be made if PSI pushes beyond its standard practice regarding reliability improvements.

While PSI had made progress with its use of S/W tools for designing system changes in an integrated way within its GIS environment, its efforts were incomplete going into 2010. Issues were finishing the merging of north and south areas data, implementing additional modules for improved functionality, and inter-changeability of design data.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Further enhancements to the existing Asset Condition Assessment (ACA)

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

methodology were developed. They included items such as adding modules (Repairs versus Replacement, Multiple Asset Decision), combining North & South area models, and updating failure curves. ACA application facilitated replacements of station circuit breakers, distribution switchgear, poles, primary cable and submersible transformers. The cable injection pilot contemplated last year was also completed for 414m of primary cable.

A DG impact study was performed. As of March 2010, 21 DG units with a total capacity of 11.2MW were connected. Another 268 with a total capacity of 26.9MW were in the application process. For PSI, wind powered DG effective capacity at peak periods was negligible. Past actual generation at PSI s peak was used as the effective capacity of gas DGs. To determine a factor for solar systems, the experience with its pilot system was analyzed. So was the technical literature on the impact of temperature on panel performance, and other jurisdiction practice. These analyses resulted in a factor of 0.75. Consequently, the total effective capacity of DG was determined and was used in load forecasting for 2011-2020. The DG offset needs to be updated in annual load forecasts.

To facilitate system planning using PSI s existing S/W tool (CYMDIST), a new application known as CYMDIST Gateway was created to interface to PSI s GIS and the other corporate systems to extract & build the required network models. The interface has built-in GIS and Power Engineering rules to validate the network models. The core interface supplier assisted with its customization. It uses the SAFE Software Feature Manipulation Engine technology, and can be fully automated to perform the extractions for network modeling. For example, extracting hundreds of feeders from the GIS and from other systems to CYMDIST can be performed in a matter of hours. Using simulations, a south service area reconfiguration plan balanced loading of transformer stations and feeders, incorporated four new feeders from (1) Greenwood TS Expansion, and (2) Markham TS4, and determined improved arrangements for the 2010 summer and 2010-11 winter. PSI wanted its system to perform within established guidelines. In 2009, one of ten transformer stations had exceeded its LTR, and some feeders were loaded above their limits. The plan was implemented so all transformer stations were within the 170MVA planning guidelines for 2010. Feeder loading was in the 400A range. In addition, however, all loadings were monitored during the summer in order to take timely corrective actions to avoid overload conditions. Other system planning activities performed included load connection assessments for 25 large C&I customers, participation in the South Simcoe Regional Study , a 44kV feeder routing for a DC, feeder integration plans and a needs assessment for Vaughan TS4.

The recommendations made last year by a specialist subcontractor, who investigated a series of pole failures caused by high winds in the Markham area, were analysed. Decisions were made on prioritizing future pole replacement, third party attachments and grade changes by municipalities. A technical assessment of commercially available software tools for structural/engineering analysis and pole line design was also performed in order to select a tool to improve current design practice.

The Reliability Committee met nine times to conduct performance reviews & comparisons, specify analysis methods, consider potential actions for short term improvement, and set an aggressive target of achieving 99.999% (Five 9 s) reliability by year end, 2015. A study examined all the factors influencing reliability, discussed initiatives with positive impacts, and ways to improve performance. The study included analyzing equipment failure history data and selected programs to improve reliability such as outage cause analysis, improvements to restoration times, WPF investigations, distribution automation, and asset condition assessment and replacement before failure, and identified 18 projects to facilitate target achievement.

Two subcontractors continued to assist with improvements in the GIS area. This assistance helped merging north and south data, implementing additional

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

61. modules, transitioning ArcFM Designer to production, and exporting Designer
62. data to AutoCAD.
63.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

1.
2.
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4.

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
2.
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Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project — **254** Name

255 1 ☐ Other employee of the company — **256** Name

257 1 ☒ External consultant — **258** Name Deloitte & Touche — **259** Firm Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Doug Fairchild	P.Eng., 23 year’s experience, Manager, System Planning & Stds
2	Richard Wang	P.Eng., 16 year’s experience, Engineer, System Planning
3	Lorne McHoull	C.E.T., 18 year’s experience Manager, GIS

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	CEATI International	89131 9899 RC0001
2	ESRI Canada Ltd.	89521 0979 RC0001
3	Kinectrics Inc.	86402 0920 RC0001
4	CYME International	14543 9956 RC0001
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What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 ☒ Project planning documents
271 1 ☒ Records of resources allocated to the project, time sheets
272 1 ☐ Design of experiments
273 1 ☒ Project records, laboratory notebooks
274 1 ☐ Design, system architecture and source code
275 1 ☒ Records of trial runs
276 1 ☒ Progress reports, minutes of project meetings
277 1 ☒ Test protocols, test data, analysis of test results, conclusions
278 1 ☐ Photographs and videos
279 1 ☐ Samples, prototypes, scrap or other artefacts
280 1 ☒ Contracts
281 1 ☒ Others, specify **282** Subcontractor report on merging north & south data

Part 2 - Project information (continued)

Project number **4**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P4: Smart metering and PSI facility energy conservation

202 Project start date: 2007-01 (Year Month)

204 Completion or expected completion date: 2011-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.01.01 | Civil engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project   **210** 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes   2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory   **226** 1 ☒ In a commercial plant or facility

224 1 ☐ In a dedicated research facility   **228** 1 ☒ Others, specify   **229** At field sites & subcontractor locations

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☐
The improvement of existing	**237** 1 ☒	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

PSI wanted to: (1) Advance its capability and methodology to deploy smart metering (SM) for all classes of customers across PSI s distribution network for automated meter reading, with seamless & reliable end-to-end data communications for settlement, that also facilitates load control for up to

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

five different end-uses, (2) Establish a closed-loop test bed for investigative trials of further potential enhancements to its SM systems, (3) Increase its detailed knowledge of the design features and methods of construction & operation that facilitate the attainment of LEED certification a different building type, and (4) Gain more understanding of the operating and performance characteristics of small scale sustainable generation systems using PV solar panels and wind resources from the pilot system in operation at its new Head Office facilities since 2008.

PSI had established a strong base level of capability with regard to smart metering, particularly at the front end of the process. While some development for the middle and back end of the process had been undertaken, further work was needed for aspects like time-of-use billing to become the new standard practice. Full integration of smart meters and their read data with the processing of this data for purposes such as time-of-use billing & settlement, and 2-way interfacing with external systems such as the provincially run Meter Data Management Repository (MDMR) still had to be achieved. In addition, PSI had no means of testing or investigating potential enhancements to its Advanced Metering Infrastructure (AMI) independent of its production systems.

PSI s new Head Office was LEED certified in 2008. In 2009, it had started to develop a new Service Centre building, which had different operational requirements. Consequently, its design solution and features were unique. However, PSI still wanted it to be LEED certified. The field trial of the pilot sustainable generation system at its head office would continue over 2010. The knowledge gained was important to PSI, prior to it developing more commercially viable sustainable generation systems.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

At the start of the year and during the course of carrying out its activities, PSI appreciated that it would have to resolve a number of problems, unknowns, challenges, issues and obstacles. They included:

1. Proven robust processes and error-free 2-way communications of meter data between PSI and the MDMR
2. Completion of the modifications required to settlement and billing software systems to leverage the mass implementation of smart meters for all classes of customers
3. The configuration and other arrangements to be used for a first field trial of smart metering applied to U/G distribution pad mounted transformers
4. The methods and metering arrangements that would be used to connect distributed generation systems embedded with PSI network territory
5. The design configuration of a dedicated testing system to investigate further potential improvements to PSI s existing AMI, and
6. The new Service Centre s design s actual performance vis-a-vis its targets for LEED certification.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Development activities for integrating smart metering internally and externally were carried over from last year. The focus was on new process development, configuring the readings data and continuing with testing and proving the quality of 2-way data exchanges with the provincially run MDMR. Two subcontractors provided assistance with the MDMR related work. A further two subcontractors were involved with the design, programming and testing of all code modifications to existing S/W tools to enable them to handle, store and process reads from smart meters and generate time-of-use bills and produce any reports PSI required for its SM efforts. Once again these activities were directed by PSI staff. New code creation and testing was an integral part of this effort. While these development activities were progressed, the

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

installation of SM equipment for all customer classes continued. By year end over 300,000 smart meters of different types were in service, all using the same communications infrastructure. Time-of-use billing had become standard practice. By June 2011, PSI anticipated SM would be standard practice with all of its customers.

A pilot trial was set up of the application of SM to distribution transformers. It involved installing a different meter - from the same supplier of the residential customer meters - on 10 pad mounted transformers and used the same existing communications infrastructure that was in place for the residential customer meters. Data from the trial was accumulated through the end of the year, but not analyzed and reviewed due lack of staff resources and other priorities. The intent was to conduct the analysis required in 2011, and from the results obtained then develop recommendations on further work on transformer smart metering.

With the launch of the FIT and micro-FIT Programs by the OPA in late 2009 to stimulate the implementation of distributed generation, PSI had to develop new standards for the metering arrangements that would have to be used in its service area to allow approved embedded generators to export power to PSI s network. By the end of the year, 194 applicants had been offered contracts by the OPA. However only a few of them had progressed to installation using the new metering standards.

With the growth in its installed base of SM equipment, PSI concluded it needed a closed loop testing system for use on a dedicated basis for investigating further potential improvements to its existing AMI, which was all being used in production. The risks of problems arising, should the existing AMI be used for trials, was simply too great. Consequently a test bed arrangement was designed that would have its own Tower Gateway Base Station, Remote Network Interface, a set of 80 meters (5 kinds from 3 suppliers) with motor loads for the meters. While the design was complete and installation begun by the end of the year, the test bed set up would not be available for use until the spring of 2011.

With respect to its facilities energy conservation, PSI staff continued with the development of its new service centre, whose design incorporated a number of green features to target LEED certification similar to that achieved with the design of its new Head Office facilities in 2008. The same two subcontractors who were involved last year provided support with respect to sustainability design, energy efficiency, building commissioning and coordination services. Occupancy was approved during the year and activities to measure and verify the service centre s as-built actual performance versus its design target were undertaken and on-going performance monitoring begun. The subcontractor, who installed the pilot sustainable generation system undergoing a field trial at PSI s head office, participated in monitoring its condition & performance and keeping it operating during the year.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

1.
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Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project — **254** Name

255 1 ☐ Other employee of the company — **256** Name

257 1 ☒ External consultant — **258** Name: Deloitte & Touche — **259** Firm: Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Rick Lapp	C.E.T., 36 years experience, ex-Manager, Metering
2	Roger Ersil	C.E.T., 21 years experience, Supervisor, Metering
3	Alan Davis	B.Sc., 16 years experience, Manager CIS Services

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	Enermodal Engineering Ltd	10163 8849 RC0001
2	Enviro-Energy Technologies Inc.	84639 3874 RC0001
3	G.G.N. Contracting	86367 2200 RC0001
4	Ideaca	89614 8210 RC0001
5	Util-Assist	84277 2741 RC0001
6	T. & W. Info-Systems	10542 9591 RC0001
7	Sky Energy Consulting	82960 0220 RC0001
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What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 ☒ Project planning documents
271 1 ☒ Records of resources allocated to the project, time sheets
272 1 ☐ Design of experiments
273 1 ☒ Project records, laboratory notebooks
274 1 ☐ Design, system architecture and source code
275 1 ☒ Records of trial runs

276 1 ☒ Progress reports, minutes of project meetings
277 1 ☒ Test protocols, test data, analysis of test results, conclusions
278 1 ☐ Photographs and videos
279 1 ☐ Samples, prototypes, scrap or other artefacts
280 1 ☒ Contracts
281 1 ☒ Others, specify **282** Subcontractor reports; SM test bed drawings; DG syste

Part 2 - Project information (continued)

Project number **5**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P5: Outage Management System development and operations

202 Project start date: 2009-01 (Year Month)

204 Completion or expected completion date: 2011-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 Electrical and electronic engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project **210** 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes 2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

	220 Names of the businesses	**221** BN
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory **226** 1 ☒ In a commercial plant or facility

224 1 ☐ In a dedicated research facility **228** 1 ☒ Others, specify **229** Subcontractor locations

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☐
The improvement of existing	**237** 1 ☒	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. It is the knowledge, expertise and capability to design, develop and implement
2. an OMS tool with a configuration, functionality and features, whose in service
3. use leads to improvements in distribution network reliability performance and
4. reduces the customer minutes of service interruptions. Such a tool would also

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

(1) facilitate better management of outages and distribution network operations from a central control centre, (2) provide system operators with a near real-time view of the state of its distribution network, and (3) establish a platform for future operational and work force automation initiatives. This advance requires a comprehensive understanding of, and operation of the essential interfaces to PSI s Customer Information System (CIS), Geographic Information System (GIS), SCADA, and Advanced Metering Infrastructure (AMI) systems. These interfaces have to be created, custom code developed and tested to ensure satisfactory seamless performance. PSI selected a specialist subcontractor in 2007 to supply a core tool known as Responder and provide assistance with the specific design and custom development of a PSI specific tool, based on Responder, which interfaced seamlessly with other PSI systems. The subcontractor was previously involved with the implementation of PSI s GIS. During 2009, interfaces with CIS and SCADA and associated customized reporting were completed, as was the AMI system interface. A functional review of the customized system was also completed using a set of test scripts. While a plan for system/tool acceptance testing was prepared and agreed, it was not implemented because new releases of the core Responder product and the GIS had to be first implemented and running on PSI s hardware. Installing these new releases meant that all the new interfaces for the OMS had to be retested to ensure that they performed in an identical manner to that of the earlier releases. At the end of the year, the issues encountered as a consequence of the new releases had all been resolved, but the system acceptance testing of PSI s OMS tool still had to be performed.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

For 2010 they were:

1. How well the interfaces between the OMS and its interfaces with other systems (GIS, SCADA, CIS and AMI) would perform during acceptance testing and whether or not any issues would arise that would require modifications for their resolution
2. Whether or not to run the existing arrangements for outage management in parallel with OMS once it was in production
3. The adequacy, in all respects, of the existing reporting capabilities custom built into OMS for their intended purpose, once OMS was in production
4. The definition and design of a new interface for the OMS that would integrate it with an Interactive Voice Recognition System that PSI also wanted to implement in the near future, and
5. The design configuration to adopt to transition the existing analog telecommunications infrastructure used by PSI s system operations staff to digital technology.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

System acceptance trials were held in January and February. Subcontractor support was provided for database matters and to fix bugs that arose in the GIS. In addition, modifications were required to add filters to the custom built interface to the AMI system. Upon completion of the trials, the OMS went live on the 1st March. For the balance of the year, the old system that the OMS was replacing was run in parallel   both required data input from a customer s call   to verify that the OMS processing and outputs were consistent and matched those of the system being replaced. This monitoring showed that the OMS was performing well and would be capable of doing everything in one when the customer call receipt was automated itself by the implementation of an Interactive Voice Recognition (IVR) System, which was planned for implementation in 2011 in PSI s Customer Relations function.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

By the end of April, sufficient experience with the OMS reporting capabilities had been gained to identify a series of modifications that had to be made to the 14 custom reports originally included in the deployment of the OMS. The need for an additional archive report was also identified. These modifications and addition were resolved over the summer with assistance from the specialist subcontractor involved with the development of OMS.

In the second half of the year, work was completed in defining and designing the interface between the IVR and OMS. This effort involved the working with the subcontractor who had helped create all of the other interfaces to the OMS system, and with a second contractor, who was assisting PSI with the selection of the IVR supplier. Requirements and specifications were first developed and reviewed prior to their inclusion in the RFP issued by PSI for IVR system selection. With the selection made for a hosted solution, the design of phase of the integration of the OMS and the IVR solution was undertaken for a web services, bi-directional interface. Design assistance was provided by the subcontractor involved with the creation of all the other OMS interfaces. The development, testing and deployment phases of the implementation of the OMS/IVR interface to integrate their operations would continue next year.

One further area was worked on during the year in the System Operations area. It was to develop the requirements and design configuration to transition the operations staff internal telephone communications infrastructure from the current analog based system to digital technology. Several issues arose with existing and possible new towers that would be used, some technical and others logistical/access related. Establishing digital profiles was involved, as was much testing using a mock platform at the new equipment s supplier location. While some progress was made with installing the new equipment, the cutover from analog to digital would not occur until 2011.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project — **254** Name

255 1 ☐ Other employee of the company — **256** Name

257 1 ☒ External consultant — **258** Name: Deloitte & Touche — **259** Firm: Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Jack Jacoby	C.E.T., 21 years' experience, Manager, System Control
2	Kris Philpott	C.E.T., 17 years' experience, Manager, GIS Development
3	John McClean	C.E.T., 26 years' experiences, Director of Operations

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	ESRI Canada Ltd	89521 0979 RC0001
2	Nielsen IT Consulting	86663 8984 RC0001
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4		
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What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 ☒ Project planning documents

271 1 ☒ Records of resources allocated to the project, time sheets

272 1 ☐ Design of experiments

273 1 ☒ Project records, laboratory notebooks

274 1 ☐ Design, system architecture and source code

275 1 ☒ Records of trial runs

276 1 ☒ Progress reports, minutes of project meetings

277 1 ☒ Test protocols, test data, analysis of test results, conclusions

278 1 ☐ Photographs and videos

279 1 ☐ Samples, prototypes, scrap or other artefacts

280 1 ☒ Contracts

281 1 ☒ Others, specify **282** Subcontractor reports and deliverables

Part 2 - Project information (continued)

Project number **6**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P6: Smart Grid initiatives development

202 Project start date: 2009-01 (Year Month)

204 Completion or expected completion date: 2015-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project

210 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes 2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory

226 1 ☒ In a commercial plant or facility

224 1 ☐ In a dedicated research facility

228 1 ☒ Others, specify **229** Field locations

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☐
The improvement of existing	**237** 1 ☒	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

1. The capability to deploy and implement a range of SG concepts and technologies
2. across PSI s existing distribution network to transition it to one that has a
3. fully intelligent infrastructure with: (1) Compatible, durable and reliable
4. equipment with built-in sensing and intelligent electronic devices for

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

monitoring, fault diagnosis, and self-restoration capabilities, (2) Fail-safe, robust, fast, high band-width, 2-way advanced communications from customers to the grid control centre, (3) Centralized monitoring and control utilizing integrated data bases for customer information, for asset records including their geographic locations, for the management of outages, for grid operations, and for making physical changes to the grid infrastructure, (4) Informed and intelligent operators and customers regarding electricity use and the assets for local generation, distribution and storage and initiatives to facilitate wise consumption for system-wide benefits, and (5) Unrestricted capability to accommodate, electric vehicles, distributed generation (DG), and potentially energy storage. An SG therefore supports 2-way flows of electricity, data & information. Previously, PSI had explored SG concepts and technologies and increased these efforts after the enactment of the Green Energy And Green Economy Act in May 2009. PS began investigating two new potential SG initiatives. The first was concerned with the development of a pilot project for a smart business park (SBP) where a dedicated closed loop distribution network would be fed from the new MTS #4. The second was for a pilot implementation of a software tool that was for Fault Detection, Isolation and Restoration (FDIR). It would operate as an extension to PSI s existing SCADA system. By the end of 2009, implementation of the SBP was on hold as the benefit/cost ratio was unfavorable, but the FDIR pilot was still being pursued with the intent of starting pilot implementation and a live trial in late April 2010. Going into 2010, PSI had, in addition, various other aspects of a SG in place or under development. They included the Outage Management System application, an installed base of residential smart meters, and CDM programs, but it did not yet have an integrated plan for SG.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

Going into the year, PSI was considering and investigating two SG related initiatives, the FDIR tool one and another related to the on-line condition monitoring of power transformers. It did not have, as already noted, a comprehensive plan with an integrated set of initiatives that it would use to transition its existing power distribution system into a modern one, as defined by the Ontario SG Forum, that Uses sensors, monitoring, communication, automation and computers to improve the flexibility, security, reliability, efficiency and safety of the electricity supply system . Up to this point in time, PSI s SG efforts had all been explored, investigated and trialed on an individual or ad hoc basis.

For 2010, the obstacles faced were:

1. The creation of an SG strategy and 5-year plan to set out the technical areas in which it should focus its SG development efforts and integrate and prioritize its initiatives within this comprehensive plan

2. A continuation of preliminary investigation of the application FDIR tool to a portion of its network and deciding whether or not to proceed with a pilot application to evaluate if adopting the use of the tool as standard practice would improve overall system performance, beyond what traditional Control Room practices could achieve. When the tool is configured to suit a particular network, the programming identifies the faulted portion of a feeder, initiates automatic operation of devices to effectively isolate the faulted portion, and re-energizes the healthy sections of the feeder again through the automatic operation of other switching devices. A feature of the tool is that it can be used in automatic mode or semi-automatic mode. With the latter method of operation, the system controller reviews and authorizes intended switching operations.

3. Evaluating the results from the pilot implementation of on-line condition monitoring of power transformers that had been started in prior years to determine whether or not such equipment monitoring should be embedded within

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

PSI s established standard practice.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

Following the decision made last year to put the SBP implementation on hold, PSI decided that it had to develop an SG strategy and plan within which its initiatives could be identified, initially assessed, integrated and prioritized. They would then be incorporated within PSI s annual capital planning and prioritization process. A start was made in February with a task force of senior staff, who undertook the development of the strategy and the comprehensive plan for the five years, 2011 through 2015, over the next 6 to 7 month period. A specialist consulting firm facilitated the efforts of the task force. These efforts culminated in the publication of the PSI SG Strategy Report, which was accepted and approved by the PSI Board of Directors in September.

As the SG strategy was being developed, the preparation for initiative to launch the FDIR tool pilot continued through October. While most of the FDIR tool s customization was carried by the tool supplier (who also was PSI s SCADA vendor) without charge, PSI staff participated in some code customization and other preparatory activities before the pilot went live in November in semi-automatic mode. The intent during the pilot trial was to collect data from monitoring what (1) the FDIR tool would do under event conditions, and (2) the Control Room (CR) staff did under the same conditions. The collected data would then be analyzed and compared to determine whether the FDIR tool s response or the CR staff s actions were more appropriate for event resolution. For the first few events experienced in the pilot trial, the FDIR tool did not perform to expectations, and so programming modifications were made with a view to improving its capabilities. The pilot would continue throughout 2011, when further modifications to the tool might be required.

The on-line transformer condition monitoring that was also launched in 2009 also continued throughout 2010. The results obtained were encouraging, and more power transformers were included in the pilot. By the end of the year, on-line power transformer condition monitoring had become part of PSI s standard practice.

With its SG strategy established, the focus of PSI s efforts shifted for the balance of the year to advancing the SG initiatives in progress, and preparing for implementing a number of SG initiatives included in the plan that PSI would be launching in future such as an electric vehicle pilot, digital fault indicators using Flexnet, more DA reclosers, a grid optimization & management pilot, high impedance GFP, and the feasibility of energy storage systems using batteries and flywheels.

Throughout the year, PSI staff actively participated on a regular basis in SG related sessions with the IESO, its industry regulators, peers, interest groups and other stakeholders in order to exchange and share information about its SG plan, initiatives and intentions, and to learn from the SG efforts of its sister LDCs such as the members of the Coalition of Large Distributors.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

3.

4.

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project — **254** Name

255 1 ☐ Other employee of the company — **256** Name

257 1 ☒ External consultant — **258** Name: Deloitte & Touche — **259** Firm: Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	John Mulrooney	P.Eng., 34 years’ experience, Director, Smart Grid Technologies
2	Ted Wojcinski	P.Eng., 28 years;’ experience, VP, Engineering Planning
3	Ed Chatten	P.Eng., 30 years’ experience , SVP, SG & Strategic Support

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

	268 Names of individuals or companies	**269** BN
1	Navigant Consulting	88310 1511 RC0001
2		
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10		

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 ☒ Project planning documents

271 1 ☒ Records of resources allocated to the project, time sheets

272 1 ☐ Design of experiments

273 1 ☒ Project records, laboratory notebooks

274 1 ☐ Design, system architecture and source code

275 1 ☒ Records of trial runs

276 1 ☒ Progress reports, minutes of project meetings

277 1 ☒ Test protocols, test data, analysis of test results, conclusions

278 1 ☐ Photographs and videos

279 1 ☐ Samples, prototypes, scrap or other artefacts

280 1 ☒ Contracts

281 1 ☒ Others, specify **282** Smart Grid Strategy Report, September 2010

Part 2 - Project information (continued)

Project number **7**

CRA internal form identifier 060
Code 1101

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

2010 P7: Sustainable generation

202 Project start date: 2009-01 (Year Month)

204 Completion or expected completion date: 2015-12 (Year Month)

206 Field of science or technology code (See guide for list of codes): 2.02.01 | Electrical and electronic engineering

Project claim history

208 1 ☒ Continuation of a previously claimed project   **210** 1 ☐ First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 ☐ Yes   2 ☒ No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
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The work was carried out (check any that apply)

223 1 ☐ In a laboratory   **226** 1 ☒ In a commercial plant or facility

224 1 ☐ In a dedicated research facility   **228** 1 ☒ Others, specify   **229** At field sites

Purpose of the work

230 1 ☒ To achieve technological advancement for the purpose of creating new or improving existing materials, devices, products or processes. (**Go to Section B** – Experimental development)

232 1 ☐ For the advancement of scientific knowledge (**Go to Section C** – Basic or applied research)

Section B – Experimental development

The technological advancements you were trying to achieve with this work were required for:

	Materials, devices, or products	Processes
The creation of new	**235** 1 ☐	**236** 1 ☐
The improvement of existing	**237** 1 ☒	**238** 1 ☒

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

PSI wanted to substantially increase its knowledge & understanding, and the application, of sustainable generation technologies, particularly with Solar PV, and the variables that are critical for such systems to be technically & commercially viable. It wanted this capability in order to develop a robust

240 What **technological** advancements were you trying to achieve? (*Maximum 50 lines*)

methodology that it could use to investigate and qualify potential locations for either custom designed or pre-engineered sustainable generation systems, which it would then implement. In 2009, PSI staff had undertaken a series of self-development activities to determine the state-of-the-art using Internet resources, specialist consultants and suppliers, seminar attendance and meetings with industry participants. PSI also participated in funding a study into the potential for using residential customers roofs for small scale Solar PV panel driven sustainable generation systems and purchased another study into the potential for micro-generation systems. In addition it: (1) conducted a technical review of applicable solar/wind systems and created a series of modular design concepts for sample systems of the kind that could be used on the roofs of commercial properties and similar facilities with large elevated areas, (2) investigated a large number of potential sites and facilities with potential to accommodate custom designed systems, and (3) performed, for roof top mounted systems, about 50 structural reviews and analysis, and preliminary systems design. By the end of 2009, none of the opportunities investigated were close to implementation. PSI s sole experience with sustainable generation systems in service continued to be its pilot application at its H.O. facilities.

242 What **technological** obstacles/uncertainties did you have to overcome to achieve the technological advancements described in Line 240? (*Maximum 50 lines*)

The obstacles that PSI had to overcome were as follows:

1. Completing its set of criteria and methodology to establish a site s/location s potential sustainable generation systems characteristics and first cut on viability that could be used for the initial evaluation of multiple sites, including the depth of detail and scope that was appropriate to evaluate the structural capacity of existing roof tops for supporting a sustainable generation system, and the extent of any strengthening measures that might be necessary

2. Determining the design and configuration for, and then implementing a commercial scale Solar PV system, comprised of several sub-systems, on a PSI owned facility for use as: (a) a test bed for establishing, comparing and contrasting the performance of different makes of panels and racking arrangements, and (b) a generator supplying energy to the grid under the FIT program, and

3. Creating a strategy for the development and operation of sustainable generating facilities, primarily using Solar PV technologies, for the next 5 to 10 years.

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

During the year PSI continued to focus on Solar PV Systems development that it had begun investigating last year. Three specialist subcontractors continued the investigations and studies into more than 50 potential locations, most of which involved roof top mounted systems, although one was ground based on 25 acres at an airport site.

While this location specific potential system work was ongoing, PSI also decided to develop it first commercial scale Solar PV systems on the roof of its own facilities at 55 Patterson Road in Barrie. The intent at the outset was that this roof would be used to house a set of systems for trial purposes and also to export power under the FIT Program. Over Phases 1 and 2, a total of 9 sub-systems would be designed and installed with an aggregate capacity of 243kW. The 9 sub-systems would each be unique combinations of panels and racking/panel supporting frames supplied by different manufacturers, so that their performance could be closely monitored and differences established under the same set of conditions. By the early fall, Phase 1 for about 40kW was

244 What work did you perform **in the tax year** to overcome the technological obstacles/uncertainties described in Line 242? (Summarize the systematic investigation) (*Maximum 100 lines*)

completed using one of the specialist subcontractors already referenced. Phase 2 was still in progress at the end of the year. It was being undertaken by another of the three subcontractors already mentioned. (The overall system and its equipment were subsequently hooked up and went into service for trials and energy exporting purposes in Aril 2011. It would be the first sustainable generating system that PSI would own and operate.)

During the year, PSI also developed, with assistance from a specialist consulting subcontractor, its strategy for the development of sustainable generation facilities for the next few years. This work also involved consideration of whether or not PSI should join or participate in a Solar PV consortium.

By the end of the year, sufficient preliminary work had been undertaken with the design and development of a number of opportunities which in aggregate amounted to about 8MW in total in capacity terms, encompassing both FIT and micro-FIT Programs that PSI was confident would proceed to implementation in 2011. To that end, three additional staff were hired late in 2010 to deal with the issues that would arise with the simultaneously implementation of a number of Solar PV sustainable generation systems in 2011.

Section C – Basic or applied research

250 What advancements in scientific knowledge were you trying to achieve? (*Maximum 50 lines*)

252 What work did you perform **in the tax year**, how did that work contribute to the advancements described in Line 250? (Summarize the systematic investigation) (*Maximum 100 lines*)

Section D – Additional project information

Who prepared the responses for Section B or Section C?

253 1 ☐ Employee directly involved in the project

254 Name

255 1 ☐ Other employee of the company

256 Name

257 1 ☒ External consultant

258 Name Deloitte & Touche

259 Firm Deloitte & Touche

List the key individuals directly involved in the project and indicate their qualifications/experience.

	260 Names	**261** Qualifications/experience and position title
1	Milan Bolkovic	P. Eng., 31years' experience, EVP, Sus. Gen. & Conservation
2	Doug Switzer	B.Sc. , 21 years' experience, VP Business Development
3	Jack Aldred	C.E.T., 17 years' experience, Manager, Key Accounts

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . 1 ☐ Yes 2 ☒ No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . 1 ☐ Yes 2 ☒ No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . 1 ☒ Yes 2 ☐ No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	**269** BN
1 Enviro-Energy Technologies Inc.	84639 3874 RC0001
2 Home Energy Solutions Ltd.	82804 1152 RC0001
3 Navigant Consulting	88310 1511 RC0001
4 Steenhof Building Services Group	87707 4815 RC0001
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What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 ☒ Project planning documents

271 1 ☒ Records of resources allocated to the project, time sheets

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273 1 ☒ Project records, laboratory notebooks

274 1 ☐ Design, system architecture and source code

275 1 ☒ Records of trial runs

276 1 ☒ Progress reports, minutes of project meetings

277 1 ☒ Test protocols, test data, analysis of test results, conclusions

278 1 ☒ Photographs and videos

279 1 ☐ Samples, prototypes, scrap or other artefacts

280 1 ☒ Contracts

281 1 ☒ Others, specify **282** Solar Consortium Investigation Report

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Choose Your Utility:	**File Number:**	**Rate Year:**
Peterborough Distribution Incorporated PowerStream Inc.	EB-2012-0161	2013

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rates & Applications
Phone Number:	(905) 532-4640
Email Address:	tom.barrett@powersrteam.ca

Copyright

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Table of Contents

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Data Input (1)

		Initial Application			(6)	Per Board Decision	
1	Rate Base						
	Gross Fixed Assets (average)	$802,388,655	(8)	$ 802,388,655		$802,388,655	
	Accumulated Depreciation (average)	($86,568,565)	(5)	($86,568,565)		($86,568,565)	
	Allowance for Working Capital:						
	Controllable Expenses	$85,701,101		$ 85,701,101		$85,701,101	
	Cost of Power	$857,779,706		$ 857,779,706		$857,779,706	
	Working Capital Rate (%)	13.00%		13.00%		13.00%	
2	Utility Income						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$162,044,558					
	Distribution Revenue at Proposed Rates	$169,487,804					
	Other Revenue:						
	Specific Service Charges	$3,385,000					
	Late Payment Charges	$2,500,000					
	Other Distribution Revenue	$2,032,000					
	Other Income and Deductions	$1,145,000					
	Total Revenue Offsets	$9,062,000	(7)				
	Operating Expenses:						
	OM+A Expenses	$83,906,062		$ 83,906,062		$83,906,062	
	Depreciation/Amortization	$35,844,204	(9)	$ 35,844,204		$35,844,204	
	Property taxes	$1,795,039		$ 1,795,039		$1,795,039	
	Other expenses						
3	Taxes/PILs						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($20,821,865)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$1,832,511					
	Income taxes (grossed up)	$2,449,645					
	Federal tax (%)	15.00%					
	Provincial tax (%)	10.19%					
	Income Tax Credits	($627,700)					
4	Capitalization/Cost of Capital						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		(2)		(2)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	4.96%					
	Short-term debt Cost Rate (%)	2.08%					
	Common Equity Cost Rate (%)	9.12%					
	Prefered Shares Cost Rate (%)						

Notes:

General Data inputs are required on Sheets 3, 10A and 10B. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) 4.0% unless an Applicant has proposed or been approved for another amount.

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) Gross Fixed assets amount is adjusted by the amounts in PP&E deferral account and GEA capital deferral accounts

(9) Depreciation amount is adjusted by the depreciation of amounts in PP&E deferral and GEA capital deferral accounts

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$802,388,655	$ -	$802,388,655	$ -	$802,388,655
2	Accumulated Depreciation (average)	(3)	($86,568,565)	$ -	($86,568,565)	$ -	($86,568,565)
3	Net Fixed Assets (average)	(3)	$715,820,090	$ -	$715,820,090	$ -	$715,820,090
4	Allowance for Working Capital	(1)	$122,652,505	$ -	$122,652,505	$ -	$122,652,505
5	**Total Rate Base**		$838,472,595	$ -	$838,472,595	$ -	$838,472,595

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$85,701,101	$ -	$85,701,101	$ -	$85,701,101
7	Cost of Power		$857,779,706	$ -	$857,779,706	$ -	$857,779,706
8	Working Capital Base		$943,480,807	$ -	$943,480,807	$ -	$943,480,807
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$122,652,505	$ -	$122,652,505	$ -	$122,652,505

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Utility Income

Line No.	Particulars	Initial Application				Per Board Decision
	Operating Revenues:					
1	Distribution Revenue (at Proposed Rates)	$169,487,804	($169,487,804)	$ -	$ -	$ -
2	Other Revenue (1)	$9,062,000	($9,062,000)	$ -	$ -	$ -
3	Total Operating Revenues	$178,549,804	($178,549,804)	$ -	$ -	$ -
	Operating Expenses:					
4	OM+A Expenses	$83,906,062	$ -	$83,906,062	$ -	$83,906,062
5	Depreciation/Amortization	$35,844,204	$ -	$35,844,204	$ -	$35,844,204
6	Property taxes	$1,795,039	$ -	$1,795,039	$ -	$1,795,039
7	Capital taxes	$ -	$ -	$ -	$ -	$ -
8	Other expense	$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)	$121,545,305	$ -	$121,545,305	$ -	$121,545,305
10	Deemed Interest Expense	$23,967,373	($23,967,373)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)	$145,512,678	($23,967,373)	$121,545,305	$ -	$121,545,305
12	**Utility income before income taxes**	$33,037,126	($154,582,431)	($121,545,305)	$ -	($121,545,305)
13	Income taxes (grossed-up)	$2,449,645	$ -	$2,449,645	$ -	$2,449,645
14	**Utility net income**	$30,587,481	($154,582,431)	($123,994,950)	$ -	($123,994,950)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$3,385,000		$ -		$ -
	Late Payment Charges	$2,500,000		$ -		$ -
	Other Distribution Revenue	$2,032,000		$ -		$ -
	Other Income and Deductions	$1,145,000		$ -		$ -
	Total Revenue Offsets	$9,062,000	$ -	$ -	$ -	$ -

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$30,587,480	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($20,821,865)	$ -	($20,821,865)
3	Taxable income	$9,765,615	$ -	($20,821,865)
	Calculation of Utility income Taxes			
4	Income taxes	$1,832,511	$1,832,511	$1,832,511
6	Total taxes	$1,832,511	$1,832,511	$1,832,511
7	Gross-up of Income Taxes	$617,134	$617,134	$617,134
8	Grossed-up Income Taxes	$2,449,645	$2,449,645	$2,449,645
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,449,645	$2,449,645	$2,449,645
10	Other tax Credits	($627,700)	($627,700)	($627,700)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	10.19%	10.19%	10.19%
13	Total tax rate (%)	25.19%	25.19%	25.19%

Notes

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$469,544,653	4.96%	$23,269,764
2	Short-term Debt	4.00%	$33,538,904	2.08%	$697,609
3	**Total Debt**	60.00%	$503,083,557	4.76%	$23,967,373
	Equity				
4	Common Equity	40.00%	$335,389,038	9.12%	$30,587,480
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$335,389,038	9.12%	$30,587,480
7	**Total**	100.00%	$838,472,595	6.51%	$54,554,853

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$838,472,595	0.00%	$ -

Per Board Decision

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.96%	$ -
9	Short-term Debt	0.00%	$ -	2.08%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.12%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$838,472,595	0.00%	$ -

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$7,443,273		($48,350,517)		$121,545,305
2	Distribution Revenue	$162,044,558	$162,044,531	$162,044,558	$217,838,321	$ -	($121,545,305)
3	Other Operating Revenue Offsets - net	$9,062,000	$9,062,000	$ -	$ -	$ -	$ -
4	**Total Revenue**	$171,106,558	$178,549,804	$162,044,558	$169,487,804	$ -	$ -
5	Operating Expenses	$121,545,305	$121,545,305	$121,545,305	$121,545,305	$121,545,305	$121,545,305
6	Deemed Interest Expense	$23,967,373	$23,967,373	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$145,512,678	$145,512,678	$121,545,305	$121,545,305	$121,545,305	$121,545,305
7	**Utility Income Before Income Taxes**	$25,593,880	$33,037,126	$40,499,253	$47,942,499	($121,545,305)	($121,545,305)
8	Tax Adjustments to Accounting Income per 2009 PILs	($20,821,865)	($20,821,865)	($20,821,865)	($20,821,865)	$ -	$ -
9	**Taxable Income**	$4,772,015	$12,215,261	$19,677,388	$27,120,634	($121,545,305)	($121,545,305)
10	Income Tax Rate	25.19%	25.19%	25.19%	25.19%	25.19%	25.19%
11	**Income Tax on Taxable Income**	$1,202,204	$3,077,366	$4,957,285	$6,832,447	($30,620,666)	($30,620,666)
12	**Income Tax Credits**	($627,700)	($627,700)	($627,700)	($627,700)	$ -	$ -
13	**Utility Net Income**	$25,019,376	$30,587,481	$36,169,668	($123,994,950)	($90,924,639)	($123,994,950)
14	**Utility Rate Base**	$838,472,595	$838,472,595	$838,472,595	$838,472,595	$838,472,595	$838,472,595
	Deemed Equity Portion of Rate Base	$335,389,038	$335,389,038	$ -	$ -	$ -	$ -
15	Income/(Equity Portion of Rate Base)	7.46%	9.12%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.12%	9.12%	0.00%	0.00%	0.00%	0.00%
17	Deficiency/Sufficiency in Return on Equity	-1.66%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	5.84%	6.51%	4.31%	0.00%	-10.84%	0.00%
19	Requested Rate of Return on Rate Base	6.51%	6.51%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Rate of Return	-0.66%	0.00%	4.31%	0.00%	-10.84%	0.00%
21	Target Return on Equity	$30,587,480	$30,587,480	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	$5,568,104	$1	($36,169,668)	$ -	$90,924,639	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	$7,443,273 **(1)**		($48,350,517) **(1)**		$121,545,305 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$83,906,062		$83,906,062		$83,906,062	
2	Amortization/Depreciation	$35,844,204		$35,844,204		$35,844,204	
3	Property Taxes	$1,795,039		$1,795,039		$1,795,039	
5	Income Taxes (Grossed up)	$2,449,645		$2,449,645		$2,449,645	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$23,967,373		$ -		$ -	
	Return on Deemed Equity	$30,587,480		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$178,549,803		$123,994,950		$123,994,950	
9	Revenue Offsets	$9,062,000		$ -		$ -	
10	**Base Revenue Requirement**	$169,487,803		$123,994,950		$123,994,950	
11	Distribution revenue	$169,487,804		$ -		$ -	
12	Other revenue	$9,062,000		$ -		$ -	
13	**Total revenue**	$178,549,804		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	(1)	($123,994,950)	(1)	($123,994,950)	(1)

Notes

(1) Line 11 - Line 8

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - Residential (1)

○ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 800 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 11.9900	1	$ 11.99	$ 13.5700	1	$ 13.57	$ 1.58	13.18%
2	Smart Meter Rate Adder	monthly	$ 1.2800	1	$ 1.28		1	$ -	-$ 1.28	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
4	Service Charge Rate Rider(s)	monthly	$ 0.1400	1	$ 0.14		1	$ -	-$ 0.14	-100.00%
5	Distribution Volumetric Rate	per kWh	$ 0.0135	800	$ 10.80	$ 0.0151	800	$ 12.08	$ 1.28	11.85%
6	Low Voltage Rate Adder	per kWh	$ 0.0001	800	$ 0.08	$ 0.0003	800	$ 0.24	$ 0.16	200.00%
7	Volumetric Rate Adder(s)	per kWh	-$ 0.0004	800	-$ 0.32		800	$ -	$ 0.32	-100.00%
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider			800	$ -		800	$ -	$ -	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 23.97**			**$ 26.09**	**$ 2.12**	**8.84%**
17	RTSR - Network	per kWh	$ 0.0073	823.92	$ 6.01	$ 0.0071	827.6	$ 5.88	-$ 0.14	-2.31%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0027	823.92	$ 2.22	$ 0.0032	827.6	$ 2.65	$ 0.42	19.05%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 32.21**			**$ 34.61**	**$ 2.41**	**7.47%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	823.92	$ 4.28	$ 0.0052	827.6	$ 4.30	$ 0.02	0.45%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	823.92	$ 0.91	$ 0.0011	827.6	$ 0.91	$ 0.00	0.45%
22	Special Purpose Charge	per kWh	$ -	823.92	$ -	$ -	827.6	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh	$ 0.0762	823.92	$ 62.75	$ 0.0762	827.6	$ 63.03	$ 0.28	0.45%
26		per kWh			$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 106.00**			**$ 108.71**	**$ 2.71**	**2.56%**
29	HST		13%		$ 13.78	13%		$ 14.13	$ 0.35	2.56%
30	**Total Bill (including Sub-total B)**				**$ 119.78**			**$ 122.84**	**$ 3.06**	**2.55%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 11.98**	-10%		**-$ 12.28**	**-$ 0.30**	**2.50%**
32	**Total Bill (including OCEB)**				**$ 107.80**			**$ 110.56**	**$ 2.76**	**2.56%**
33	**Loss Factor (%)**	**Note 1**	2.99%			3.45%				

Notes:

(1): Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used.There is a small rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream South rate zone

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - Residential (2)

○ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 800 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 15.3400	1	$ 15.34	$ 13.5700	1	$ 13.57	-$ 1.77	-11.54%
2	Smart Meter Rate Adder	monthly		1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
4	Service Charge Rate Rider(s)	monthly	$ 1.7800	1	$ 1.78		1	$ -	-$ 1.78	-100.00%
5	Distribution Volumetric Rate	per kWh	$ 0.0137	800	$ 10.96	$ 0.0151	800	$ 12.08	$ 1.12	10.22%
6	Low Voltage Rate Adder	per kWh	$ 0.0008	800	$ 0.64	$ 0.0003	800	$ 0.24	-$ 0.40	-62.50%
7	Volumetric Rate Adder(s)	per kWh		800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)	per kWh	-$ 0.0006	800	-$ 0.48		800	$ -	$ 0.48	-100.00%
9	Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	800	-$ 0.48	-$ 0.0006	800	-$ 0.48	$ -	0.00%
12	Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	$ 0.0008	800	$ 0.64	$ 0.64	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 28.08**			**$ 26.57**	**-$ 1.51**	**-5.38%**
17	RTSR - Network	per kWh	$ 0.0069	845.2	$ 5.83	$ 0.0071	827.6	$ 5.88	$ 0.04	0.76%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0054	845.2	$ 4.56	$ 0.0032	827.6	$ 2.65	-$ 1.92	-41.97%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 38.48**			**$ 35.09**	**-$ 3.38**	**-8.79%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	845.2	$ 4.40	$ 0.0052	827.6	$ 4.30	-$ 0.09	-2.08%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	845.2	$ 0.93	$ 0.0011	827.6	$ 0.91	-$ 0.02	-2.08%
22	Special Purpose Charge	per kWh		845.2	$ -	$ -	827.6	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh	$ 0.0757	845.2	$ 63.98	$ 0.0757	827.6	$ 62.65	-$ 1.33	-2.08%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 113.63**			**$ 108.81**	**-$ 4.82**	**-4.25%**
29	HST		13%		$ 14.77	13%		$ 14.14	-$ 0.63	-4.25%
30	**Total Bill (including Sub-total B)**				**$ 128.40**			**$ 122.95**	**-$ 5.45**	**-4.24%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 12.84**	-10%		**-$ 12.30**	**$ 0.54**	**-4.21%**
32	**Total Bill (including OCEB)**				**$ 115.56**			**$ 110.65**	**-$ 4.91**	**-4.25%**
33	**Loss Factor (%)**	**Note 1**	5.65%			3.45%				

Notes:

(1): Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used. There is a small rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream Barrie rate zone

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - General Service < 50 kW (1)

● Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 2000 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 28.6400	1	$ 28.64	$ 27.9100	1	$ 27.91	-$ 0.73	-2.55%
2	Smart Meter Rate Adder	monthly	$ 1.0100	1	$ 1.01		1	$ -	-$ 1.01	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
4	Service Charge Rate Rider(s)	monthly	$ 3.3700	1	$ 3.37		1	$ -	-$ 3.37	-100.00%
5	Distribution Volumetric Rate	per kWh	$ 0.0116	2000	$ 23.20	$ 0.0148	2000	$ 29.60	$ 6.40	27.59%
6	Low Voltage Rate Adder	per kWh	$ 0.0001	2000	$ 0.20	$ 0.0003	2000	$ 0.60	$ 0.40	200.00%
7	Volumetric Rate Adder(s)	per kWh		2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)	per kWh	-$ 0.0003	2000	-$ 0.60		2000	$ -	$ 0.60	-100.00%
9	Smart Meter Disposition Rider	per kWh		2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider	per kWh		2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	per kWh		2000	$ -	-$ 0.0012	2000	-$ 2.40	-$ 2.40	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 55.82**			**$ 55.91**	**$ 0.09**	**0.16%**
17	RTSR - Network	per kWh	$ 0.0066	2059.8	$ 13.59	$ 0.0065	2069	$ 13.45	-$ 0.15	-1.08%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0024	2059.8	$ 4.94	$ 0.0028	2069	$ 5.79	$ 0.85	17.19%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 74.36**			**$ 75.15**	**$ 0.79**	**1.07%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2059.8	$ 10.71	$ 0.0052	2069	$ 10.76	$ 0.05	0.45%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2059.8	$ 2.27	$ 0.0011	2069	$ 2.28	$ 0.01	0.45%
22	Special Purpose Charge	per kWh		2059.8	$ -		2069	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0833	2059.8	$ 171.50	$ 0.0833	2069	$ 172.26	$ 0.77	0.45%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 273.08**			**$ 274.70**	**$ 1.62**	**0.59%**
29	HST		13%		$ 35.50	13%		$ 35.71	$ 0.21	0.59%
30	**Total Bill (including Sub-total B)**				**$ 308.58**			**$ 310.41**	**$ 1.83**	**0.59%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 30.86**	-10%		**-$ 31.04**	**-$ 0.18**	**0.58%**
32	**Total Bill (including OCEB)**				**$ 277.72**			**$ 279.37**	**$ 1.65**	**0.59%**
33	**Loss Factor**	(1)	2.99%			3.45%				

Notes:

(1): See Note (1) from Sheet 10A. Bill Impacts - Residential

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used. There is a rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream South rate zone

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - General Service < 50 kW (2)

● Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 2000 **kWh**

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 16.1100	1	$ 16.11	$ 27.9100	1	$ 27.91	$ 11.80	73.25%
2	Smart Meter Rate Adder	monthly		1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)	monthly	$ 4.7300	1	$ 4.73	$ 0.2000	1	$ 0.20	-$ 4.53	-95.77%
4	Service Charge Rate Rider(s)	monthly		1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0164	2000	$ 32.80	$ 0.0148	2000	$ 29.60	-$ 3.20	-9.76%
6	Low Voltage Rate Adder	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0003	2000	$ 0.60	-$ 0.80	-57.14%
7	Volumetric Rate Adder(s)	per kWh		2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)	per kWh	-$ 0.0004	2000	-$ 0.80		2000	$ -	$ 0.80	-100.00%
9	Smart Meter Disposition Rider	per kWh		2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0007	2000	$ 1.40	$ -	0.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0004	2000	-$ 0.80	-$ 0.0004	2000	-$ 0.80	$ -	0.00%
12	Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0009	2000	-$ 1.80	-$ 1.80	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 54.84**			**$ 57.11**	**$ 2.27**	**4.14%**
17	RTSR - Network	per kWh	$ 0.0063	2113	$ 13.31	$ 0.0065	2069	$ 13.45	$ 0.14	1.03%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0048	2113	$ 10.14	$ 0.0028	2069	$ 5.79	-$ 4.35	-42.88%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 78.29**			**$ 76.35**	**-$ 1.94**	**-2.48%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2113	$ 10.99	$ 0.0052	2069	$ 10.76	-$ 0.23	-2.08%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2113	$ 2.32	$ 0.0011	2069	$ 2.28	-$ 0.05	-2.08%
22	Special Purpose Charge	per kWh		2113	$ -		2069	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0834	2113	$ 176.19	$ 0.0834	2069	$ 172.52	-$ 3.67	-2.08%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 282.05**			**$ 276.16**	**-$ 5.89**	**-2.09%**
29	HST		13%		$ 36.67	13%		$ 35.90	-$ 0.77	-2.09%
30	**Total Bill (including Sub-total B)**				**$ 318.71**			**$ 312.06**	**-$ 6.65**	**-2.09%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 31.87**	-10%		**-$ 31.21**	**$ 0.66**	**-2.07%**
32	**Total Bill (including OCEB)**				**$ 286.84**			**$ 280.85**	**-$ 5.99**	**-2.09%**
33	**Loss Factor**	(1)	5.65%			3.45%				

Notes:

(1): See Note (1) from Sheet 10A. Bill Impacts - Residential

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used. There is a rounding difference to Appendix 2-V.
(3) These Bill Impacts are for PowerStream Barrie rate zone

PowerStream Energy Load Model Drivers
PS Consolidated Jan 2002 - Dec 2011

								Outliers			
Year	**Month**	**Gross Purchases MWh**	**CDD18**	**HDD10**	**GDP**	**Feb**	**Apr**	**Jul-10**	**May-09**	**Aug-03**	**Oct-03**
2002	1	**648,141**	**0.0**	**325.5**	**0.51**	**0**	**0**	0	0	0	0
2002	2	**593,198**	**0.0**	**316.4**	**0.72**	**1**	**0**	0	0	0	0
2002	3	**628,227**	**0.0**	**297.6**	**0.88**	**0**	**0**	0	0	0	0
2002	4	**595,135**	**8.3**	**82.5**	**1.02**	**0**	**1**	0	0	0	0
2002	5	**604,018**	**7.8**	**0.0**	**1.14**	**0**	**0**	0	0	0	0
2002	6	**661,273**	**70.0**	**0.0**	**1.24**	**0**	**0**	0	0	0	0
2002	7	**793,206**	**192.4**	**0.0**	**1.34**	**0**	**0**	0	0	0	0
2002	8	**749,567**	**142.7**	**0.0**	**1.44**	**0**	**0**	0	0	0	0
2002	9	**669,740**	**87.6**	**0.0**	**1.52**	**0**	**0**	0	0	0	0
2002	10	**633,405**	**10.0**	**35.7**	**1.61**	**0**	**0**	0	0	0	0
2002	11	**634,781**	**0.0**	**204.0**	**1.69**	**0**	**0**	0	0	0	0
2002	12	**655,689**	**0.0**	**372.0**	**1.76**	**0**	**0**	0	0	0	0
2003	1	**707,086**	**0.0**	**565.8**	**1.79**	**0**	**0**	0	0	0	0
2003	2	**641,302**	**0.0**	**474.6**	**1.83**	**1**	**0**	0	0	0	0
2003	3	**661,928**	**0.0**	**333.3**	**1.86**	**0**	**0**	0	0	0	0
2003	4	**612,757**	**2.4**	**130.5**	**1.89**	**0**	**1**	0	0	0	0
2003	5	**607,840**	**0.0**	**0.0**	**1.92**	**0**	**0**	0	0	0	0
2003	6	**655,654**	**52.9**	**0.0**	**1.95**	**0**	**0**	0	0	0	0
2003	7	**729,638**	**118.3**	**0.0**	**1.98**	**0**	**0**	0	0	0	0
2003	8	**695,230**	**128.0**	**0.0**	**2.01**	**0**	**0**	0	0	**1**	0
2003	9	**633,603**	**24.0**	**0.0**	**2.04**	**0**	**0**	0	0	0	0
2003	10	**649,240**	**0.0**	**29.5**	**2.07**	**0**	**0**	0	0	0	**1**
2003	11	**644,011**	**0.0**	**159.0**	**2.09**	**0**	**0**	0	0	0	0
2003	12	**678,539**	**0.0**	**314.7**	**2.12**	**0**	**0**	0	0	0	0
2004	1	**734,924**	**0.0**	**599.9**	**2.17**	**0**	**0**	0	0	0	0
2004	2	**663,761**	**0.0**	**385.0**	**2.22**	**1**	**0**	0	0	0	0
2004	3	**685,307**	**0.0**	**240.3**	**2.27**	**0**	**0**	0	0	0	0
2004	4	**623,909**	**0.0**	**91.5**	**2.32**	**0**	**1**	0	0	0	0
2004	5	**637,436**	**8.6**	**0.0**	**2.36**	**0**	**0**	0	0	0	0
2004	6	**664,921**	**31.3**	**0.0**	**2.41**	**0**	**0**	0	0	0	0
2004	7	**715,224**	**81.5**	**0.0**	**2.45**	**0**	**0**	0	0	0	0
2004	8	**702,483**	**63.6**	**0.0**	**2.50**	**0**	**0**	0	0	0	0
2004	9	**678,092**	**42.4**	**0.0**	**2.54**	**0**	**0**	0	0	0	0
2004	10	**647,420**	**1.5**	**0.0**	**2.58**	**0**	**0**	0	0	0	0
2004	11	**665,217**	**0.0**	**139.5**	**2.62**	**0**	**0**	0	0	0	0
2004	12	**715,926**	**0.0**	**395.3**	**2.66**	**0**	**0**	0	0	0	0
2005	1	**736,155**	**0.0**	**522.4**	**2.71**	**0**	**0**	0	0	0	0
2005	2	**659,920**	**0.0**	**392.0**	**2.75**	**1**	**0**	0	0	0	0
2005	3	**705,973**	**0.0**	**361.2**	**2.79**	**0**	**0**	0	0	0	0
2005	4	**639,295**	**0.0**	**67.5**	**2.83**	**0**	**1**	0	0	0	0
2005	5	**650,847**	**0.8**	**0.0**	**2.88**	**0**	**0**	0	0	0	0
2005	6	**806,394**	**146.3**	**0.0**	**2.92**	**0**	**0**	0	0	0	0
2005	7	**829,556**	**188.7**	**0.0**	**2.96**	**0**	**0**	0	0	0	0
2005	8	**803,438**	**140.7**	**0.0**	**2.99**	**0**	**0**	0	0	0	0
2005	9	**701,298**	**52.1**	**0.0**	**3.03**	**0**	**0**	0	0	0	0
2005	10	**671,652**	**7.6**	**0.0**	**3.07**	**0**	**0**	0	0	0	0
2005	11	**684,869**	**0.0**	**148.5**	**3.11**	**0**	**0**	0	0	0	0
2005	12	**723,726**	**0.0**	**417.0**	**3.15**	**0**	**0**	0	0	0	0

PowerStream Energy Load Model Drivers
PS Consolidated Jan 2002 - Dec 2011

								Outliers			
Year	Month	Gross Purchases MWh	CDD18	HDD10	GDP	Feb	Apr	Jul-10	May-09	Aug-03	Oct-03
2006	1	732,616	0.0	303.8	3.18	0	0	0	0	0	0
2006	2	678,047	0.0	380.8	3.21	1	0	0	0	0	0
2006	3	718,688	0.0	268.2	3.24	0	0	0	0	0	0
2006	4	631,458	0.0	54.0	3.27	0	1	0	0	0	0
2006	5	687,437	26.0	0.0	3.30	0	0	0	0	0	0
2006	6	743,208	73.6	0.0	3.33	0	0	0	0	0	0
2006	7	840,310	167.3	0.0	3.36	0	0	0	0	0	0
2006	8	785,933	101.6	0.0	3.39	0	0	0	0	0	0
2006	9	656,761	12.9	0.0	3.42	0	0	0	0	0	0
2006	10	684,000	1.1	40.3	3.45	0	0	0	0	0	0
2006	11	691,035	0.0	142.5	3.48	0	0	0	0	0	0
2006	12	705,042	0.0	254.2	3.51	0	0	0	0	0	0
2007	1	753,835	0.0	398.4	3.53	0	0	0	0	0	0
2007	2	715,260	0.0	515.2	3.55	1	0	0	0	0	0
2007	3	725,410	0.0	297.6	3.58	0	0	0	0	0	0
2007	4	665,398	0.0	117.0	3.60	0	1	0	0	0	0
2007	5	690,776	22.4	0.0	3.62	0	0	0	0	0	0
2007	6	777,489	99.2	0.0	3.65	0	0	0	0	0	0
2007	7	780,763	106.1	0.0	3.67	0	0	0	0	0	0
2007	8	822,246	141.0	0.0	3.69	0	0	0	0	0	0
2007	9	704,462	47.5	0.0	3.71	0	0	0	0	0	0
2007	10	699,578	19.8	0.0	3.74	0	0	0	0	0	0
2007	11	709,184	0.0	223.5	3.76	0	0	0	0	0	0
2007	12	736,790	0.0	382.9	3.78	0	0	0	0	0	0
2008	1	771,035	0.0	375.1	3.77	0	0	0	0	0	0
2008	2	723,329	0.0	427.0	3.77	1	0	0	0	0	0
2008	3	735,147	0.0	362.7	3.76	0	0	0	0	0	0
2008	*4*	670,354	0.0	15.0	*3.75*	0	*1*	0	0	0	0
2008	*5*	669,096	2.5	0.0	*3.75*	0	*0*	0	0	0	0
2008	*6*	743,772	71.5	0.0	*3.74*	0	*0*	0	0	0	0
2008	*7*	806,541	111.0	0.0	*3.73*	0	*0*	0	0	0	0
2008	*8*	746,570	64.0	0.0	*3.73*	0	*0*	0	0	0	0
2008	*9*	693,013	26.7	0.0	*3.72*	0	*0*	0	0	0	0
2008	*10*	683,229	0.0	31.0	*3.71*	0	*0*	0	0	0	0
2008	*11*	692,181	0.0	211.5	*3.71*	0	*0*	0	0	0	0
2008	*12*	738,678	0.0	406.1	*3.70*	0	*0*	0	0	0	0
2009	*1*	768,218	0.0	581.3	*3.67*	0	*0*	0	0	0	0
2009	*2*	673,005	0.0	395.9	*3.63*	1	*0*	0	0	0	0
2009	*3*	708,633	0.0	285.2	*3.59*	0	*0*	0	0	0	0
2009	*4*	657,533	1.2	66.0	*3.55*	0	*1*	0	0	0	0
2009	*5*	644,299	6.9	0.0	*3.52*	0	*0*	0	1	0	0
2009	*6*	678,296	34.2	0.0	*3.48*	0	*0*	0	0	0	0
2009	*7*	705,773	43.7	0.0	*3.44*	0	*0*	0	0	0	0
2009	*8*	774,749	91.0	0.0	*3.40*	0	*0*	0	0	0	0
2009	*9*	684,843	20.9	0.0	*3.36*	0	*0*	0	0	0	0
2009	*10*	683,702	0.0	40.3	*3.32*	0	*0*	0	0	0	0
2009	*11*	680,910	0.0	121.5	*3.28*	0	*0*	0	0	0	0
2009	*12*	746,395	0.0	382.9	*3.24*	0	*0*	0	0	0	0

PowerStream Energy Load Model Drivers
PS Consolidated Jan 2002 - Dec 2011

								Outliers			
Year	**Month**	**Gross Purchases MWh**	**CDD18**	**HDD10**	**GDP**	**Feb**	**Apr**	**Jul-10**	**May-09**	**Aug-03**	**Oct-03**
2010	*1*	771,339	0.0	471.2	3.28	0	0	0	0	0	0
2010	*2*	693,009	0.0	373.8	3.32	1	0	0	0	0	0
2010	*3*	710,538	0.0	175.2	3.35	0	0	0	0	0	0
2010	*4*	641,438	0.0	0.0	3.39	0	1	0	0	0	0
2010	*5*	709,952	45.7	0.0	3.43	0	0	0	0	0	0
2010	*6*	730,106	58.7	0.0	3.46	0	0	0	0	0	0
2010	*7*	875,547	164.9	0.0	3.50	0	0	1	0	0	0
2010	*8*	828,473	138.8	0.0	3.54	0	0	0	0	0	0
2010	*9*	687,839	31.5	0.0	3.57	0	0	0	0	0	0
2010	*10*	673,820	0.0	0.0	3.61	0	0	0	0	0	0
2010	*11*	694,449	0.0	165.0	3.64	0	0	0	0	0	0
2010	*12*	757,080	0.0	426.3	3.67	0	0	0	0	0	0
2011	*1*	783,035	0.0	527.3	3.70	0	0	0	0	0	0
2011	*2*	700,611	0.0	430.2	3.72	1	0	0	0	0	0
2011	*3*	746,275	0.0	324.8	3.75	0	0	0	0	0	0
2011	*4*	664,726	0.0	92.3	3.77	0	1	0	0	0	0
2011	*5*	682,984	13.0	0.0	3.80	0	0	0	0	0	0
2011	*6*	734,191	52.2	0.0	3.82	0	0	0	0	0	0
2011	*7*	886,672	198.6	0.0	3.84	0	0	0	0	0	0
2011	*8*	816,129	122.2	0.0	3.87	0	0	0	0	0	0
2011	*9*	702,202	39.7	0.0	3.89	0	0	0	0	0	0
2011	*10*	686,071	2.4	0.0	3.92	0	0	0	0	0	0
2011	*11*	690,309	0.0	102.0	3.94	0	0	0	0	0	0
2011	12	733,416	0.0	285.2	3.96	0	0	0	0	0	0
2012	1		0.0	467.0	3.98	0	0	0	0	0	0
2012	2		0.0	409.2	4.00	1	0	0	0	0	0
2012	3		0.0	294.5	4.02	0	0	0	0	0	0
2012	4		1.2	71.7	4.04	0	1	0	0	0	0
2012	5		13.4	0.0	4.06	0	0	0	0	0	0
2012	6		69.0	0.0	4.08	0	0	0	0	0	0
2012	7		137.3	0.0	4.10	0	0	0	0	0	0
2012	8		113.4	0.0	4.12	0	0	0	0	0	0
2012	9		38.5	0.0	4.14	0	0	0	0	0	0
2012	10		4.2	17.7	4.15	0	0	0	0	0	0
2012	11		0.0	161.7	4.17	0	0	0	0	0	0
2012	12		0.0	363.8	4.19	0	0	0	0	0	0
2013	1		0.0	467.0	4.21	0	0	0	0	0	0
2013	2		0.0	409.2	4.24	1	0	0	0	0	0
2013	3		0.0	294.5	4.26	0	0	0	0	0	0
2013	4		1.2	71.7	4.28	0	1	0	0	0	0
2013	5		13.4	0.0	4.30	0	0	0	0	0	0
2013	6		69.0	0.0	4.32	0	0	0	0	0	0
2013	7		137.3	0.0	4.35	0	0	0	0	0	0
2013	8		113.4	0.0	4.37	0	0	0	0	0	0
2013	9		38.5	0.0	4.39	0	0	0	0	0	0
2013	10		4.2	17.7	4.41	0	0	0	0	0	0
2013	11		0.0	161.7	4.43	0	0	0	0	0	0
2013	12		0.0	363.8	4.45	0	0	0	0	0	0

V2.2

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Choose Your Utility:

Woodstock Hydro Services Inc.
PowerStream Inc.

Application Type: CoS
OEB Application #: EB-XXXX-XXXX
LDC Licence #: ED-2004-0420

Last COS OEB Application #: EB-2008-0244
Last COS Re-Basing Year: 2009

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rates & Applications
Phone Number:	905-532-4640
Email Address:	tom.barrett@powerstream.ca

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Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR - Network PS South	RTSR - Connection PS South	RTSR - Network PS Barrie	RTSR - Connection PS Barrie
Residential	kWh	$ 0.0073	$ 0.0027	$ 0.0069	$ 0.0054
General Service Less Than 50 kW	kWh	$ 0.0066	$ 0.0024	$ 0.0063	$ 0.0048
General Service 50 to 4,999 kW	kW	$ 2.6667	$ 0.9755	$ 2.4796	$ 1.8993
General Service 50 to 4,999 kW - Time of Use	kW	$ 2.6667	$ 0.9755	$ 3.2918	$ 2.5212
Large Use	kW	$ 3.1285	$ 1.1529	$ 3.1192	$ 2.5775
Unmetered Scattered Load	kWh	$ 0.0066	$ 0.0027	$ 0.0063	$ 0.0048
Sentinel Lighting	kW	$ 2.0378	$ 0.8272	$ -	$ -
Street Lighting	kW	$ 2.0174	$ 0.7584	$ 1.9589	$ 1.5002

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

		PowerStream Inc.					
Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	2,727,580,225	-			2,823,992,647	-
General Service Less Than 50 kW	kWh	1,039,793,445	-			1,076,459,625	-
General Service 50 to 4,999 kW	kW	2,228,535,851	6,616,438		**46.16%**	2,304,791,121	6,616,438
General Service 50 to 4,999 kW - Time of Use	kW	2,299,723,799	5,440,457		**57.94%**	2,378,256,815	5,440,457
Large Use	kW	27,116,405	80,298		**46.29%**	27,238,429	80,298
Unmetered Scattered Load	kWh	12,446,475	-			12,897,891	-
Sentinel Lighting	kW	429,377	1,113		**52.86%**	442,215	1,113
Street Lighting	kW	59,196,079	165,046		**49.16%**	61,288,554	165,046

		PS South					
Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	2,169,017,329		1.0299		2,233,870,947	-
General Service Less Than 50 kW	kWh	830,156,008		1.0299		854,977,673	-
General Service 50 to 4,999 kW	kW	1,866,804,730	5,552,954	1.0299	**46.08%**	1,922,622,192	5,552,954
General Service 50 to 4,999 kW - Time of Use	kW	1,932,382,666	4,593,459	1.0299	**57.66%**	1,990,160,908	4,593,459
Large Use	kW	27,116,405	80,298	1.0045	**46.29%**	27,238,429	80,298
Unmetered Scattered Load	kWh	9,466,519		1.0299		9,749,568	-
Sentinel Lighting	kW	429,377	1,113	1.0299	**52.86%**	442,215	1,113
Street Lighting	kW	47,071,564	131,120	1.0299	**49.20%**	48,479,004	131,120

		PS Barrie					
Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	558,562,896		1.0565		590,121,700	-
General Service Less Than 50 kW	kWh	209,637,437		1.0565		221,481,952	-
General Service 50 to 4,999 kW	kW	361,731,121	1,063,485	1.0565	**46.62%**	382,168,929	1,063,485
General Service 50 to 4,999 kW - Time of Use	kW	367,341,133	846,998	1.0565	**59.44%**	388,095,907	846,998
Large Use	kW	-	-	1.0045		-	-
Unmetered Scattered Load	kWh	2,979,955		1.0565		3,148,323	-
Sentinel Lighting	kW	-	-	1.0565		-	-
Street Lighting	kW	12,124,515	33,926	1.0565	**48.98%**	12,809,550	33,926

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

Uniform Transmission Rates

Rate Description	Unit	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate	Effective January 1, 2013 Rate
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.57
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.80
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.86

Hydro One Sub-Transmission Rates

Rate Description	Unit	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate	Effective January 1, 2013 Rate
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A

Rate Description	Unit	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate	Effective January 1, 2013 Rate
RSVA Transmission network – 4714 – which affects 1584	kW			
RSVA Transmission connection – 4716 – which affects 1586	kW			
RSVA LV – 4750 – which affects 1550	kW			
RARA 1 – 2252 – which affects 1590	kW			
Hydro One Sub-Transmission Rate Rider 6A	kW	$ -	$ -	$ -

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	1,172,677	$3.22	$ 3,776,020	1,278,848	$0.79	$ 1,010,290	369,020	$1.77	$ 653,165	$ 1,663,455
February	1,155,701	$3.22	$ 3,721,357	1,240,997	$0.79	$ 980,388	366,830	$1.77	$ 649,289	$ 1,629,677
March	1,096,699	$3.22	$ 3,531,371	1,186,982	$0.79	$ 937,716	352,812	$1.77	$ 624,477	$ 1,562,193
April	1,020,257	$3.22	$ 3,285,228	1,120,382	$0.79	$ 885,102	322,505	$1.77	$ 570,834	$ 1,455,936
May	1,344,705	$3.22	$ 4,329,950	1,402,268	$0.79	$ 1,107,792	390,700	$1.77	$ 691,539	$ 1,799,331
June	1,517,759	$3.22	$ 4,887,184	1,579,226	$0.79	$ 1,247,589	409,182	$1.77	$ 724,252	$ 1,971,841
July	1,697,698	$3.22	$ 5,466,588	1,744,521	$0.79	$ 1,378,172	455,649	$1.77	$ 806,499	$ 2,184,670
August	1,402,917	$3.22	$ 4,517,393	1,447,538	$0.79	$ 1,143,555	377,247	$1.77	$ 667,727	$ 1,811,282
September	1,310,425	$3.22	$ 4,219,569	1,363,751	$0.79	$ 1,077,363	357,285	$1.77	$ 632,394	$ 1,709,758
October	1,002,508	$3.22	$ 3,228,076	1,089,505	$0.79	$ 860,709	307,533	$1.77	$ 544,333	$ 1,405,042
November	1,093,578	$3.22	$ 3,521,321	1,148,048	$0.79	$ 906,958	333,605	$1.77	$ 590,481	$ 1,497,439
December	1,092,418	$3.22	$ 3,517,586	1,158,785	$0.79	$ 915,440	325,356	$1.77	$ 575,880	$ 1,491,320
Total	14,907,342	$ 3.22	$ 48,001,641	15,760,851	$ 0.79	$ 12,451,072	4,367,724	$ 1.77	$ 7,730,871	$ 20,181,944

HYDRO ONE

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	197,286	$2.65	$ 522,808	197,374	$0.64	$ 126,319	197,374	$1.50	$ 296,061	$ 422,380
February	199,292	$2.65	$ 528,124	199,357	$0.64	$ 127,588	199,357	$1.50	$ 299,036	$ 426,624
March	192,373	$2.65	$ 509,788	192,632	$0.64	$ 123,284	192,632	$1.50	$ 288,948	$ 412,232
April	172,465	$2.65	$ 457,032	174,584	$0.64	$ 111,734	174,584	$1.50	$ 261,876	$ 373,610
May	232,307	$2.65	$ 615,614	232,420	$0.64	$ 148,749	232,420	$1.50	$ 348,630	$ 497,379
June	250,079	$2.65	$ 662,709	250,079	$0.64	$ 160,051	250,079	$1.50	$ 375,119	$ 535,169
July	264,449	$2.65	$ 700,790	265,188	$0.64	$ 169,720	265,188	$1.50	$ 397,782	$ 567,502
August	217,896	$2.65	$ 577,424	218,103	$0.64	$ 139,586	218,103	$1.50	$ 327,155	$ 466,740
September	199,470	$2.65	$ 528,596	199,515	$0.64	$ 127,690	199,515	$1.50	$ 299,273	$ 426,962
October	177,897	$2.65	$ 471,427	178,763	$0.64	$ 114,408	178,763	$1.50	$ 268,145	$ 382,553
November	184,333	$2.65	$ 488,481	188,896	$0.64	$ 120,894	188,896	$1.50	$ 283,344	$ 404,238
December	194,257	$2.65	$ 514,781	194,337	$0.64	$ 124,376	194,337	$1.50	$ 291,506	$ 415,881
Total	2,482,104	$ 2.65	$ 6,577,574	2,491,248	$ 0.64	$ 1,594,399	2,491,248	$ 1.50	$ 3,736,872	$ 5,331,271

TOTAL

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	1,369,963	$3.14	$ 4,298,828	1,476,222	$0.77	$ 1,136,609	566,394	$1.68	$ 949,226	$ 2,085,836
February	1,354,993	$3.14	$ 4,249,481	1,440,354	$0.77	$ 1,107,976	566,187	$1.67	$ 948,325	$ 2,056,301
March	1,289,072	$3.13	$ 4,041,159	1,379,614	$0.77	$ 1,061,000	545,444	$1.67	$ 913,425	$ 1,974,426
April	1,192,722	$3.14	$ 3,742,260	1,294,966	$0.77	$ 996,836	497,089	$1.68	$ 832,710	$ 1,829,545
May	1,577,012	$3.14	$ 4,945,564	1,634,688	$0.77	$ 1,256,541	623,120	$1.67	$ 1,040,169	$ 2,296,710
June	1,767,838	$3.14	$ 5,549,893	1,829,305	$0.77	$ 1,407,639	659,261	$1.67	$ 1,099,371	$ 2,507,010
July	1,962,147	$3.14	$ 6,167,377	2,009,709	$0.77	$ 1,547,892	720,837	$1.67	$ 1,204,281	$ 2,752,173
August	1,620,813	$3.14	$ 5,094,817	1,665,641	$0.77	$ 1,283,141	595,350	$1.67	$ 994,882	$ 2,278,023
September	1,509,895	$3.14	$ 4,748,164	1,563,266	$0.77	$ 1,205,053	556,800	$1.67	$ 931,667	$ 2,136,720
October	1,180,405	$3.13	$ 3,699,503	1,268,268	$0.77	$ 975,117	486,296	$1.67	$ 812,478	$ 1,787,595
November	1,277,911	$3.14	$ 4,009,802	1,336,944	$0.77	$ 1,027,852	522,501	$1.67	$ 873,825	$ 1,901,677
December	1,286,675	$3.13	$ 4,032,367	1,353,122	$0.77	$ 1,039,816	519,693	$1.67	$ 867,386	$ 1,907,201
Total	17,389,446	$ 3.14	$ 54,579,216	18,252,099	$ 0.77	$ 14,045,471	6,858,972	$ 1.67	$ 11,467,744	$ 25,513,215

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	1,172,677	$ 3.5700	$ 4,186,457	1,278,848	$ 0.8000	$ 1,023,078	369,020	$ 1.8600	$ 686,377	$ 1,709,456
February	1,155,701	$ 3.5700	$ 4,125,853	1,240,997	$ 0.8000	$ 992,798	366,830	$ 1.8600	$ 682,304	$ 1,675,101
March	1,096,699	$ 3.5700	$ 3,915,215	1,186,982	$ 0.8000	$ 949,586	352,812	$ 1.8600	$ 656,230	$ 1,605,816
April	1,020,257	$ 3.5700	$ 3,642,317	1,120,382	$ 0.8000	$ 896,306	322,505	$ 1.8600	$ 599,859	$ 1,496,165
May	1,344,705	$ 3.5700	$ 4,800,597	1,402,268	$ 0.8000	$ 1,121,814	390,700	$ 1.8600	$ 726,702	$ 1,848,516
June	1,517,759	$ 3.5700	$ 5,418,400	1,579,226	$ 0.8000	$ 1,263,381	409,182	$ 1.8600	$ 761,079	$ 2,024,459
July	1,697,698	$ 3.5700	$ 6,060,782	1,744,521	$ 0.8000	$ 1,395,617	455,649	$ 1.8600	$ 847,507	$ 2,243,124
August	1,402,917	$ 3.5700	$ 5,008,414	1,447,538	$ 0.8000	$ 1,158,030	377,247	$ 1.8600	$ 701,679	$ 1,859,710
September	1,310,425	$ 3.5700	$ 4,678,217	1,363,751	$ 0.8000	$ 1,091,001	357,285	$ 1.8600	$ 664,550	$ 1,755,551
October	1,002,508	$ 3.5700	$ 3,578,954	1,089,505	$ 0.8000	$ 871,604	307,533	$ 1.8600	$ 572,011	$ 1,443,615
November	1,093,578	$ 3.5700	$ 3,904,073	1,148,048	$ 0.8000	$ 918,438	333,605	$ 1.8600	$ 620,505	$ 1,538,944
December	1,092,418	$ 3.5700	$ 3,899,932	1,158,785	$ 0.8000	$ 927,028	325,356	$ 1.8600	$ 605,162	$ 1,532,190
Total	14,907,342	$ 3.57	$ 53,219,211	15,760,851	$ 0.80	$ 12,608,681	4,367,724	$ 1.86	$ 8,123,967	$ 20,732,647

HYDRO ONE	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	197,286	$ 2.6500	$ 522,808	197,374	$ 0.6400	$ 126,319	197,374	$ 1.5000	$ 296,061	$ 422,380
February	199,292	$ 2.6500	$ 528,124	199,357	$ 0.6400	$ 127,588	199,357	$ 1.5000	$ 299,036	$ 426,624
March	192,373	$ 2.6500	$ 509,788	192,632	$ 0.6400	$ 123,284	192,632	$ 1.5000	$ 288,948	$ 412,232
April	172,465	$ 2.6500	$ 457,032	174,584	$ 0.6400	$ 111,734	174,584	$ 1.5000	$ 261,876	$ 373,610
May	232,307	$ 2.6500	$ 615,614	232,420	$ 0.6400	$ 148,749	232,420	$ 1.5000	$ 348,630	$ 497,379
June	250,079	$ 2.6500	$ 662,709	250,079	$ 0.6400	$ 160,051	250,079	$ 1.5000	$ 375,119	$ 535,169
July	264,449	$ 2.6500	$ 700,790	265,188	$ 0.6400	$ 169,720	265,188	$ 1.5000	$ 397,782	$ 567,502
August	217,896	$ 2.6500	$ 577,424	218,103	$ 0.6400	$ 139,586	218,103	$ 1.5000	$ 327,155	$ 466,740
September	199,470	$ 2.6500	$ 528,596	199,515	$ 0.6400	$ 127,690	199,515	$ 1.5000	$ 299,273	$ 426,962
October	177,897	$ 2.6500	$ 471,427	178,763	$ 0.6400	$ 114,408	178,763	$ 1.5000	$ 268,145	$ 382,553
November	184,333	$ 2.6500	$ 488,481	188,896	$ 0.6400	$ 120,894	188,896	$ 1.5000	$ 283,344	$ 404,238
December	194,257	$ 2.6500	$ 514,781	194,337	$ 0.6400	$ 124,376	194,337	$ 1.5000	$ 291,506	$ 415,881
Total	2,482,104	$ 2.65	$ 6,577,574	2,491,248	$ 0.64	$ 1,594,399	2,491,248	$ 1.50	$ 3,736,872	$ 5,331,271

TOTAL	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	1,369,963	$ 3.44	$ 4,709,265	1,476,222	$ 0.78	$ 1,149,398	566,394	$ 1.73	$ 982,438	$ 2,131,836
February	1,354,993	$ 3.43	$ 4,653,976	1,440,354	$ 0.78	$ 1,120,386	566,187	$ 1.73	$ 981,339	$ 2,101,725
March	1,289,072	$ 3.43	$ 4,425,004	1,379,614	$ 0.78	$ 1,072,870	545,444	$ 1.73	$ 945,178	$ 2,018,048
April	1,192,722	$ 3.44	$ 4,099,350	1,294,966	$ 0.78	$ 1,008,039	497,089	$ 1.73	$ 861,735	$ 1,869,775
May	1,577,012	$ 3.43	$ 5,416,210	1,634,688	$ 0.78	$ 1,270,563	623,120	$ 1.73	$ 1,075,332	$ 2,345,895
June	1,767,838	$ 3.44	$ 6,081,109	1,829,305	$ 0.78	$ 1,423,431	659,261	$ 1.72	$ 1,136,197	$ 2,559,628
July	1,962,147	$ 3.45	$ 6,761,572	2,009,709	$ 0.78	$ 1,565,337	720,837	$ 1.73	$ 1,245,289	$ 2,810,626
August	1,620,813	$ 3.45	$ 5,585,838	1,665,641	$ 0.78	$ 1,297,616	595,350	$ 1.73	$ 1,028,834	$ 2,326,450
September	1,509,895	$ 3.45	$ 5,206,813	1,563,266	$ 0.78	$ 1,218,690	556,800	$ 1.73	$ 963,823	$ 2,182,513
October	1,180,405	$ 3.43	$ 4,050,381	1,268,268	$ 0.78	$ 986,012	486,296	$ 1.73	$ 840,156	$ 1,826,168
November	1,277,911	$ 3.44	$ 4,392,555	1,336,944	$ 0.78	$ 1,039,332	522,501	$ 1.73	$ 903,850	$ 1,943,182
December	1,286,675	$ 3.43	$ 4,414,713	1,353,122	$ 0.78	$ 1,051,404	519,693	$ 1.73	$ 896,668	$ 1,948,071
Total	17,389,446	$ 3.44	$ 59,796,785	18,252,099	$ 0.78	$ 14,203,080	6,858,972	$ 1.73	$ 11,860,839	$ 26,063,919

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	1,172,677	$ 3.5700	$ 4,186,457	1,278,848	$ 0.8000	$ 1,023,078	369,020	$ 1.8600	$ 686,377	$ 1,709,456
February	1,155,701	$ 3.5700	$ 4,125,853	1,240,997	$ 0.8000	$ 992,798	366,830	$ 1.8600	$ 682,304	$ 1,675,101
March	1,096,699	$ 3.5700	$ 3,915,215	1,186,982	$ 0.8000	$ 949,586	352,812	$ 1.8600	$ 656,230	$ 1,605,816
April	1,020,257	$ 3.5700	$ 3,642,317	1,120,382	$ 0.8000	$ 896,306	322,505	$ 1.8600	$ 599,859	$ 1,496,165
May	1,344,705	$ 3.5700	$ 4,800,597	1,402,268	$ 0.8000	$ 1,121,814	390,700	$ 1.8600	$ 726,702	$ 1,848,516
June	1,517,759	$ 3.5700	$ 5,418,400	1,579,226	$ 0.8000	$ 1,263,381	409,182	$ 1.8600	$ 761,079	$ 2,024,459
July	1,697,698	$ 3.5700	$ 6,060,782	1,744,521	$ 0.8000	$ 1,395,617	455,649	$ 1.8600	$ 847,507	$ 2,243,124
August	1,402,917	$ 3.5700	$ 5,008,414	1,447,538	$ 0.8000	$ 1,158,030	377,247	$ 1.8600	$ 701,679	$ 1,859,710
September	1,310,425	$ 3.5700	$ 4,678,217	1,363,751	$ 0.8000	$ 1,091,001	357,285	$ 1.8600	$ 664,550	$ 1,755,551
October	1,002,508	$ 3.5700	$ 3,578,954	1,089,505	$ 0.8000	$ 871,604	307,533	$ 1.8600	$ 572,011	$ 1,443,615
November	1,093,578	$ 3.5700	$ 3,904,073	1,148,048	$ 0.8000	$ 918,438	333,605	$ 1.8600	$ 620,505	$ 1,538,944
December	1,092,418	$ 3.5700	$ 3,899,932	1,158,785	$ 0.8000	$ 927,028	325,356	$ 1.8600	$ 605,162	$ 1,532,190
Total	14,907,342	$ 3.57	$ 53,219,211	15,760,851	$ 0.80	$ 12,608,681	4,367,724	$ 1.86	$ 8,123,967	$ 20,732,647

HYDRO ONE

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	197,286	$ 2.6500	$ 522,808	197,374	$ 0.6400	$ 126,319	197,374	$ 1.5000	$ 296,061	$ 422,380
February	199,292	$ 2.6500	$ 528,124	199,357	$ 0.6400	$ 127,588	199,357	$ 1.5000	$ 299,036	$ 426,624
March	192,373	$ 2.6500	$ 509,788	192,632	$ 0.6400	$ 123,284	192,632	$ 1.5000	$ 288,948	$ 412,232
April	172,465	$ 2.6500	$ 457,032	174,584	$ 0.6400	$ 111,734	174,584	$ 1.5000	$ 261,876	$ 373,610
May	232,307	$ 2.6500	$ 615,614	232,420	$ 0.6400	$ 148,749	232,420	$ 1.5000	$ 348,630	$ 497,379
June	250,079	$ 2.6500	$ 662,709	250,079	$ 0.6400	$ 160,051	250,079	$ 1.5000	$ 375,119	$ 535,169
July	264,449	$ 2.6500	$ 700,790	265,188	$ 0.6400	$ 169,720	265,188	$ 1.5000	$ 397,782	$ 567,502
August	217,896	$ 2.6500	$ 577,424	218,103	$ 0.6400	$ 139,586	218,103	$ 1.5000	$ 327,155	$ 466,740
September	199,470	$ 2.6500	$ 528,596	199,515	$ 0.6400	$ 127,690	199,515	$ 1.5000	$ 299,273	$ 426,962
October	177,897	$ 2.6500	$ 471,427	178,763	$ 0.6400	$ 114,408	178,763	$ 1.5000	$ 268,145	$ 382,553
November	184,333	$ 2.6500	$ 488,481	188,896	$ 0.6400	$ 120,894	188,896	$ 1.5000	$ 283,344	$ 404,238
December	194,257	$ 2.6500	$ 514,781	194,337	$ 0.6400	$ 124,376	194,337	$ 1.5000	$ 291,506	$ 415,881
Total	2,482,104	$ 2.65	$ 6,577,574	2,491,248	$ 0.64	$ 1,594,399	2,491,248	$ 1.50	$ 3,736,872	$ 5,331,271

TOTAL

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	1,369,963	$ 3.44	$ 4,709,265	1,476,222	$ 0.78	$ 1,149,398	566,394	$ 1.73	$ 982,438	$ 2,131,836
February	1,354,993	$ 3.43	$ 4,653,976	1,440,354	$ 0.78	$ 1,120,386	566,187	$ 1.73	$ 981,339	$ 2,101,725
March	1,289,072	$ 3.43	$ 4,425,004	1,379,614	$ 0.78	$ 1,072,870	545,444	$ 1.73	$ 945,178	$ 2,018,048
April	1,192,722	$ 3.44	$ 4,099,350	1,294,966	$ 0.78	$ 1,008,039	497,089	$ 1.73	$ 861,735	$ 1,869,775
May	1,577,012	$ 3.43	$ 5,416,210	1,634,688	$ 0.78	$ 1,270,563	623,120	$ 1.73	$ 1,075,332	$ 2,345,895
June	1,767,838	$ 3.44	$ 6,081,109	1,829,305	$ 0.78	$ 1,423,431	659,261	$ 1.72	$ 1,136,197	$ 2,559,628
July	1,962,147	$ 3.45	$ 6,761,572	2,009,709	$ 0.78	$ 1,565,337	720,837	$ 1.73	$ 1,245,289	$ 2,810,626
August	1,620,813	$ 3.45	$ 5,585,838	1,665,641	$ 0.78	$ 1,297,616	595,350	$ 1.73	$ 1,028,834	$ 2,326,450
September	1,509,895	$ 3.45	$ 5,206,813	1,563,266	$ 0.78	$ 1,218,690	556,800	$ 1.73	$ 963,823	$ 2,182,513
October	1,180,405	$ 3.43	$ 4,050,381	1,268,268	$ 0.78	$ 986,012	486,296	$ 1.73	$ 840,156	$ 1,826,168
November	1,277,911	$ 3.44	$ 4,392,555	1,336,944	$ 0.78	$ 1,039,332	522,501	$ 1.73	$ 903,850	$ 1,943,182
December	1,286,675	$ 3.43	$ 4,414,713	1,353,122	$ 0.78	$ 1,051,404	519,693	$ 1.73	$ 896,668	$ 1,948,071
Total	17,389,446	$ 3.44	$ 59,796,785	18,252,099	$ 0.78	$ 14,203,080	6,858,972	$ 1.73	$ 11,860,839	$ 26,063,919

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

		PowerStream Inc.				PS South					PS Barrie							RTSR Network	
Rate Class	Unit	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount %	Billed Amount %	Current RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network	PS South	PS North
Residential	kWh	2,823,992,647	-	$ 20,379,098	33.6%	$ 0.0073	2,233,870,947	-	$ 16,307,258	32.9%	$ 0.0069	590,121,700	-	$ 4,071,840	37.1%	$ 20,119,432	$ 0.0071	-2.4%	3.3%
General Service Less Than 50 kW	kWh	1,076,459,625	-	$ 7,038,189	11.6%	$ 0.0066	854,977,673	-	$ 5,642,853	11.4%	$ 0.0063	221,481,952	-	$ 1,395,336	12.7%	$ 6,948,510	$ 0.0065	-2.2%	2.5%
General Service 50 to 4,999 kW	kW	2,304,791,121	6,616,438	$ 17,445,078	28.8%	$ 2.6667	1,922,622,192	5,552,954	$ 14,808,061	29.9%	$ 2.4796	382,168,929	1,063,485	$ 2,637,017	24.0%	$ 17,222,797	$ 2.6030	-2.4%	5.0%
General Service 50 to 4,999 kW - Time of Use	kW	2,378,256,815	5,440,457	$ 15,037,526	24.8%	$ 2.6667	1,990,160,908	4,593,459	$ 12,249,378	24.7%	$ 3.2918	388,095,907	846,998	$ 2,788,148	25.4%	$ 14,845,922	$ 2.7288	2.3%	-17.1%
Large Use	kW	27,238,429	80,298	$ 251,213	0.4%	$ 3.1285	27,238,429	80,298	$ 251,213	0.5%	$ 3.1192	-	-	$ -	0.0%	$ 248,013	$ 3.0886	-1.3%	-1.0%
Unmetered Scattered Load	kWh	12,897,891	-	$ 84,182	0.1%	$ 0.0066	9,749,568	-	$ 64,347	0.1%	$ 0.0063	3,148,323	-	$ 19,834	0.2%	$ 83,109	$ 0.0064	-2.4%	2.3%
Sentinel Lighting	kW	442,215	1,113	$ 2,269	0.0%	$ 2.0378	442,215	1,113	$ 2,269	0.0%	$ -	-	-	$ -	0.0%	$ 2,240	$ 2.0118	-1.3%	
Street Lighting	kW	61,288,554	165,046	$ 330,980	0.5%	$ 2.0174	48,479,004	131,120	$ 264,522	0.5%	$ 1.9589	12,809,550	33,926	$ 66,458	0.6%	$ 326,763	$ 1.9798	-1.9%	1.1%
				$ 60,568,535					$ 49,589,902					$ 10,978,633					

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY

PowerStream Inc. - - CoS

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

		PowerStream Inc.				PS South					PS Barrie							RTSR Connection	
Rate Class	Unit	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount %	Billed Amount %	Current RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Connection	PS South	PS North
Residential	kWh	2,823,992,647	-	$ 9,218,109	34.6%	$ 0.0027	2,233,870,947	-	$ 6,031,452	33.1%	$ 0.0054	590,121,700	-	$ 3,186,657	37.6%	$ 9,008,087	$ 0.0032	18.1%	-40.9%
General Service Less Than 50 kW	kWh	1,076,459,625	-	$ 3,115,060	11.7%	$ 0.0024	854,977,673	-	$ 2,051,946	11.3%	$ 0.0048	221,481,952	-	$ 1,063,113	12.5%	$ 3,044,088	$ 0.0028	17.8%	-41.1%
General Service 50 to 4,999 kW	kW	2,304,791,121	6,616,438	$ 7,436,783	27.9%	$ 0.9755	1,922,622,192	5,552,954	$ 5,416,906	29.8%	$ 1.8993	382,168,929	1,063,485	$ 2,019,877	23.8%	$ 7,267,346	$ 1.0984	12.6%	-42.2%
General Service 50 to 4,999 kW - Time of Use	kW	2,378,256,815	5,440,457	$ 6,616,371	24.8%	$ 0.9755	1,990,160,908	4,593,459	$ 4,480,920	24.6%	$ 2.5212	388,095,907	846,998	$ 2,135,451	25.2%	$ 6,465,626	$ 1.1884	21.8%	-52.9%
Large Use	kW	27,238,429	80,298	$ 92,576	0.3%	$ 1.1529	27,238,429	80,298	$ 92,576	0.5%	$ 2.5775	-	-	$ -	0.0%	$ 90,467	$ 1.1266	-2.3%	-56.3%
Unmetered Scattered Load	kWh	12,897,891	-	$ 41,436	0.2%	$ 0.0027	9,749,568	-	$ 26,324	0.1%	$ 0.0048	3,148,323	-	$ 15,112	0.2%	$ 40,492	$ 0.0031	16.3%	-34.6%
Sentinel Lighting	kW	442,215	1,113	$ 921	0.0%	$ 0.8272	442,215	1,113	$ 921	0.0%	$ -	-	-	$ -	0.0%	$ 900	$ 0.8084	-2.3%	
Street Lighting	kW	61,288,554	165,046	$ 150,337	0.6%	$ 0.7584	48,479,004	131,120	$ 99,442	0.5%	$ 1.5002	12,809,550	33,926	$ 50,896	0.6%	$ 146,912	$ 0.8901	17.4%	-40.7%
				$ 26,671,593					$ 18,200,486					$ 8,471,106					

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY

PowerStream Inc. - - CoS

The purpose of this sheet is to update the re-aligned RTS Network Rates to recover forecast wholesale network

		PowerStream Inc.				PS South					PS Barrie						
Rate Class	Unit	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount %	Billed Amount %	Adjusted RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Adjusted RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	2,823,992,647	-	$ 20,119,432	33.6%	$ 0.0071	2,233,870,947	-	$ 15,915,132	32.5%	$ 0.0071	590,121,700	-	$ 4,204,300	38.9%	$ 20,119,432	$ 0.0071
General Service Less Than 50 kW	kWh	1,076,459,625	-	$ 6,948,510	11.6%	$ 0.0065	854,977,673	-	$ 5,518,852	11.3%	$ 0.0065	221,481,952	-	$ 1,429,658	13.2%	$ 6,948,510	$ 0.0065
General Service 50 to 4,999 kW	kW	2,304,791,121	6,616,438	$ 17,222,797	28.8%	$ 2.6030	1,922,622,192	5,552,954	$ 14,454,513	29.5%	$ 2.6030	382,168,929	1,063,485	$ 2,768,284	25.6%	$ 17,222,797	$ 2.6030
General Service 50 to 4,999 kW - Time of Use	kW	2,378,256,815	5,440,457	$ 14,845,922	24.8%	$ 2.7288	1,990,160,908	4,593,459	$ 12,534,633	25.6%	$ 2.7288	388,095,907	846,998	$ 2,311,288	21.4%	$ 14,845,922	$ 2.7288
Large Use	kW	27,238,429	80,298	$ 248,013	0.4%	$ 3.0886	27,238,429	80,298	$ 248,013	0.5%	$ 3.0886	-	-	$ -	0.0%	$ 248,013	$ 3.0886
Unmetered Scattered Load	kWh	12,897,891	-	$ 83,109	0.1%	$ 0.0064	9,749,568	-	$ 62,822	0.1%	$ 0.0064	3,148,323	-	$ 20,287	0.2%	$ 83,109	$ 0.0064
Sentinel Lighting	kW	442,215	1,113	$ 2,240	0.0%	$ 2.0118	442,215	1,113	$ 2,240	0.0%	$ 2.0118	-	-	$ -	0.0%	$ 2,240	$ 2.0118
Street Lighting	kW	61,288,554	165,046	$ 326,763	0.5%	$ 1.9798	48,479,004	131,120	$ 259,595	0.5%	$ 1.9798	12,809,550	33,926	$ 67,167	0.6%	$ 326,763	$ 1.9798
				$ 59,796,785					$ 48,995,800					$ 10,800,986			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY

PowerStream Inc. - - CoS

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection

		PowerStream Inc.				PS South					PS Barrie						
Rate Class	Unit	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount %	Billed Amount %	Adjusted RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Adjusted RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	2,823,992,647	-	$ 9,008,087	34.6%	$ 0.0032	2,233,870,947	-	$ 7,125,693	33.4%	$ 0.0032	590,121,700	-	$ 1,882,394	39.9%	$ 9,008,087	$ 0.0032
General Service Less Than 50 kW	kWh	1,076,459,625	-	$ 3,044,088	11.7%	$ 0.0028	854,977,673	-	$ 2,417,766	11.3%	$ 0.0028	221,481,952	-	$ 626,322	13.3%	$ 3,044,088	$ 0.0028
General Service 50 to 4,999 kW	kW	2,304,791,121	6,616,438	$ 7,267,346	27.9%	$ 1.0984	1,922,622,192	5,552,954	$ 6,099,239	28.6%	$ 1.0984	382,168,929	1,063,485	$ 1,168,108	24.7%	$ 7,267,346	$ 1.0984
General Service 50 to 4,999 kW - Time of Use	kW	2,378,256,815	5,440,457	$ 6,465,626	24.8%	$ 1.1884	1,990,160,908	4,593,459	$ 5,459,025	25.6%	$ 1.1884	388,095,907	846,998	$ 1,006,601	21.3%	$ 6,465,626	$ 1.1884
Large Use	kW	27,238,429	80,298	$ 90,467	0.3%	$ 1.1266	27,238,429	80,298	$ 90,467	0.4%	$ 1.1266	-	-	$ -	0.0%	$ 90,467	$ 1.1266
Unmetered Scattered Load	kWh	12,897,891	-	$ 40,492	0.2%	$ 0.0031	9,749,568	-	$ 30,608	0.1%	$ 0.0031	3,148,323	-	$ 9,884	0.2%	$ 40,492	$ 0.0031
Sentinel Lighting	kW	442,215	1,113	$ 900	0.0%	$ 0.8084	442,215	1,113	$ 900	0.0%	$ 0.8084	-	-	$ -	0.0%	$ 900	$ 0.8084
Street Lighting	kW	61,288,554	165,046	$ 146,912	0.6%	$ 0.8901	48,479,004	131,120	$ 116,714	0.5%	$ 0.8901	12,809,550	33,926	$ 30,198	0.6%	$ 146,912	$ 0.8901
				$ 26,063,919					$ 21,340,411					$ 4,723,508			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

PowerStream Inc. - - CoS

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 Rate Generator.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0071	$ 0.0032
General Service Less Than 50 kW	kWh	$ 0.0065	$ 0.0028
General Service 50 to 4,999 kW	kW	$ 2.6030	$ 1.0984
General Service 50 to 4,999 kW - Time of Use	kW	$ 2.7288	$ 1.1884
Large Use	kW	$ 3.0886	$ 1.1266
Unmetered Scattered Load	kWh	$ 0.0064	$ 0.0031
Sentinel Lighting	kW	$ 2.0118	$ 0.8084
Street Lighting	kW	$ 1.9798	$ 0.8901