APPENDIX 1
SCHEDULES FOR EXHIBIT A

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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

Ontario Energy Board	Commission de l'Énergie de l'Ontario
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2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
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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;

"**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;

"**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;

"**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.

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.

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.

The 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.

> 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.
EB-2008-0244
Proposed Issues List

1. Rate Base (Exhibit B)

1.1 Transformer Stations (B1-5-2 and B1-5-4)

1.2 Corporate Head Office (B1-5-3)

2. Operating Revenue (Exhibit C)

2.1 Forecast Methodology (C1-1-2)

3. Operating Costs (Exhibit D)

3.1 2009 OM&A forecast (D1-1-1)

4. Rate Design (Exhibit I)

4.1 Lost Revenue Adjustment Mechanism and Shared Savings Mechanism (I-2-1)

4.2 Smart Meters (I-3-1)

4.3 Proposed Tariffs (I-6-2)

Schedule 3

EB-2007-0074 - DECISION AND ORDER DATED JULY 26, 2007

EB-2007-0850 – DECISION DATED MARCH 17, 2008 & RATE ORDER DATED APRIL 17, 2008

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2007-0074

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 rates for distribution service.

BEFORE: Cynthia Chaplin
Presiding Member

Paul Vlahos
Member

Cathy Spoel
Member

DECISION AND ORDER

On March 7, 2007, PowerStream Inc. ("PowerStream") filed an Application with the Ontario Energy Board (the "Board) pursuant to section 78 of the *Ontario Energy Board Act, 1988* for an order or orders approving or fixing just and reasonable rates for the distribution of electricity. PowerStream is a licensed distributor providing electrical service to consumers within its defined service areas as specified in its licence ED-2004-0420 in the Town of Markham ("Markham"), the Town of Richmond Hill ("Richmond Hill"), the City of Vaughan ("Vaughan"), and the Town of Aurora ("Aurora"). This Application was filed by PowerStream in response to the Board's direction in RP-2005-0020/EB2006-0409 to bring forward a proposal to harmonize its rates in 2007. Prior to this Application, four sets of rates were in effect, one for each municipality served.

Public notice of the Application was given through newspaper publication in Powerstream's service area. The evidence filed in support of the Application was made available for review by interested members of the public. While the Board has considered the entire record in this proceeding, and has found it sufficient, it has made reference in this Decision only to such parts of the record as are necessary to provide context to its findings.

To harmonize its rates, PowerStream performed the following four steps:

1. Combined the approved 2006 EDR revenue requirements of PowerStream and Aurora as adjusted for the new capital structure and PILs, and combined Retail Transmission Rates and distribution losses to produce one set of new 2006 rates using the 2006 EDR model,
2. Allocated the combined 2006 revenue requirement to the rate classes using the Board developed cost allocation model and compared those allocated costs to the revenues from the combined 2006 rates to determine the differences between the rates and allocated costs,
3. Re-aligned the combined 2006 rates by closing the differences by 25% between the allocated costs and the combined rates by rate class, and
4. Applied the re-aligned 2006 rates to the 2007 IRM model to produce the proposed rates for which PowerStream is seeking approval.

In support of this application, PowerStream pre-filed evidence and appeared at a Technical Conference held at the Board's offices on June 11, 2007.

In reviewing the evidence the Board considered the following:

1. What is the impact on revenue requirement?
2. Is the proposal to incorporate the Board's proposed cost allocation model reasonable?
3. Was the Board's final finding for the price cap index adjustment in 2007 EDR applied to the 2007 IRM Model?
4. Are the changes in the levels of the fixed monthly charges reasonable?
5. Are the total bill impacts reasonable?
6. What is an appropriate implementation date?
7. Other rate matters addressed by PowerStream in their application; combining Retail Transmission Rates, combining distribution losses, and the treatment of Regulatory Assets.

For the reasons set out below, the Board approves PowerStream's application.

Revenue Requirement Impact

The application is not revenue neutral. The 2006 revenue requirement for PowerStream increases by $111,272 to $104,330,964 from $104,219,692, which represents about a 0.1% increase. The main drivers for the net change in the revenue requirement arise from the acquisition of Aurora Hydro. They are:

- Changing Aurora's Debt Equity ratio from 50/50 to 60/40, debt to equity,
- Retiring Aurora's $12,736,000 promissory note at 7.25% and replacing it with a note at the deemed rate of 6.12%.

As a result of these changes in capital structure and debt costs, Net Income Before PILs and PILs changed, which resulted in a net increase in the revenue requirement.

The Board approves the changes in capital structure and related costs for the purposes of setting the 2006 revenue requirement as the first step in the harmonization of rates. In making this finding, the Board considered the increase in revenue requirement to be *de minimis* in the context of this application.

The Move to Allocated Costs

In the second step in harmonization PowerStream allocated its harmonized 2006 EDR costs to the rate classes using the cost allocation model issued by the Board on November 15, 2006. The combined rates were used to develop revenues for comparison to the allocated costs. PowerStream proposes to reduce the difference between the revenues and the allocated costs by 25% for each rate class. This step is revenue neutral for the utility in totality.

While the cost allocation model was developed collaboratively with stakeholders, the Board has not yet made a decision on the implementation of the model in rate making. However, as PowerStream is not proposing to fully implement the allocated costs arising from the model, there will be an opportunity to make any adjustments that might be required once the Board has made a decision on the use of the cost allocation model. The Board finds this approach to be reasonable.

Application of the Price Cap Index Adjustment to the 2007 IRM Model

The Board notes that the application by PowerStream was submitted prior to the Decision on the 2007 price cap index adjustment in the 2007 EDR. In its Decision in 2007 EDR, the Board approved a price cap index adjustment of 1.90%. PowerStream's application incorporated the default rate of 1.92% coded into the model distributed by Board staff for the 2007 EDR. The Board has reflected the approved 1.90% in setting the final rates.

Fixed Monthly Charges

The split between the fixed monthly charge and the variable charge is proposed to change upon harmonization. Every existing rate would be moved to a new common rate resulting from applying the harmonized costs to the 2006 EDR model. Thus, a change for all would naturally occur. The overall changes to the fixed/variable split in rates are not more than 3%. The Board accepts the resulting proposed fixed monthly charges.

Total Bill Impacts from Harmonization

Based on the evidence, no rate class would experience an increase greater than 10%, except for street lighting and sentinel lighting. The Board recognizes that when rates are harmonized, some customers will experience an increase and others a decrease. In the case of its residential customers, PowerStream's evidence shows that the largest increase for a typical residential customer would occur in Vaughan (2.5%) and the largest decrease in Aurora (8.2%). For General Service customers (less than 50 kW) using 2,000 kWh, the change in bills would range from +2.5% (in Markham) to -5.9% (in Aurora).

The total bill for street lighting in Markham would increase by 17.3%. However, PowerStream pointed out that Markham has mitigated the impact by contracting for supply through a third party. The total bill for sentinel lights, i.e. security lighting in farm lanes and other places, would increase by over 20%. The Board notes, however, that the maximum bill increase would only be $3.95 due to the low monthly bill for sentinel lighting.

The Board finds these changes to be reasonable under the circumstances surrounding harmonization of PowerStream's rates.

Implementation Date

The original application did not include an implementation date. At the Technical Conference, PowerStream stated that they would not want an effective date later than November 1, 2007. PowerStream also advised that they would appreciate a month to effect the changes to the billing system and prepare customer communication material. The Board directs PowerStream to implement the rates effective November 1, 2007.

Other Rate Matters

In the process of harmonization, PowerStream also addressed the issues of combining Retail Transmission Rates and incorporating distribution losses. The proposed approach would result in all customers paying the same average rate for retail transmission service and distribution losses. The Board accepts this blending of these costs as proposed in the application.

PowerStream, however, did not propose blending the Regulatory Assets. PowerStream proposed to keep the existing charges separate in the four operating areas. PowerStream pointed out that these costs were incurred prior to amalgamation and should therefore remain separate. The Board agrees with this and directs that PowerStream maintain the Regulatory Asset accounts separately by operating area until the rate riders associated with the Regulatory Assets account are removed.

Costs

The Board directs that the Board’s costs of, and incidental to, this proceeding be paid by PowerStream immediately upon receipt of the Board’s invoice.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix “A” of this Order is approved, effective November 1, 2007.

2. The Tariff of Rates and Charges set out in Appendix “A” of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for PowerStream Inc. and Aurora Hydro Connections Inc.

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, July 26, 2007.

ONTARIO ENERGY BOARD

Original Signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix "A"

EB-2007-0074

July 26, 2007

ONTARIO ENERGY BOARD

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective November 1, 2007

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

EB-2007-0074

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 – November 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – November 1, 2007 for all charges incurred by customers on or after that date
LOSS FACTOR ADJUSTMENT – November 1, 2007 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.

General Service 50 to 4,999 kW – Legacy
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. Usage is measured by a time of use meter, which is a device that measures and records electrical usage during pre-specified periods of the day cumulatively over a meter reading period. This legacy classification refers to two accounts located in Markham only.

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.
TARIFF OF RATES AND CHARGES
Effective November 1, 2007

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

EB-2007-0074

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	$	12.71
Distribution Volumetric Rate	$/kWh	0.0131
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0029
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	29.34
Distribution Volumetric Rate	$/kWh	0.0114
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	301.56
Distribution Volumetric Rate	$/kW	2.3556
Retail Transmission Rate – Network Service Rate	$/kW	2.1907
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0403
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 – 4,999 kW – Legacy

Service Charge	$	3,304.07
Distribution Volumetric Rate	$/kW	1.6540
Retail Transmission Rate – Network Service Rate	$/kW	2.3211
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0751
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	8,951.97
Distribution Volumetric Rate	$/kW	1.2997
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5701
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.2295
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective November 1, 2007

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EB-2007-0074

Unmetered Scattered Load

Service Charge (per connection)	$	14.31
Distribution Volumetric Rate	$/kWh	0.0114
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0028
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.00
Distribution Volumetric Rate	$/kW	6.0660
Retail Transmission Rate – Network Service	$/kW	1.6740
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8821
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.84
Distribution Volumetric Rate	$/kW	3.4582
Retail Transmission Rate – Network Service Rate	$/kW	1.6573
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8089
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective November 1, 2007

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

EB-2007-0074

Rate Riders for Regulatory Asset Recovery
(In Effect until and including April 30, 2008)

These rate riders are to collect the amount of the Regulatory Asset Account balances which are kept separately for each of the former rate zones of PowerStream Inc.

Residential		
Regulatory Asset Recovery, Aurora	$/kWh	0.0051
Regulatory Asset Recovery, Markham	$/kWh	(0.0007)
Regulatory Asset Recovery, Richmond Hill	$/kWh	(0.0010)
Regulatory Asset Recovery, Vaughan	$/kWh	(0.0017)
General Service Less Than 50 kW		
Regulatory Asset Recovery, Aurora	$/kWh	0.0039
Regulatory Asset Recovery, Markham	$/kWh	(0.0012)
Regulatory Asset Recovery, Richmond Hill	$/kWh	(0.0003)
Regulatory Asset Recovery, Vaughan	$/kWh	(0.0022)
General Service 50 to 4,999 kW		
Regulatory Asset Recovery, Aurora	$/kW	1.3376
Regulatory Asset Recovery, Markham	$/kW	(0.3898)
Regulatory Asset Recovery, Richmond Hill	$/kW	(0.0082)
Regulatory Asset Recovery, Vaughan	$/kW	(0.4488)
General Service 50 – 4,999 kW – Legacy		
Regulatory Asset Recovery, Markham	$/kW	(0.9205)
Large Use		
Regulatory Asset Recovery, Vaughan	$/kW	(0.9271)
Unmetered Scattered Load		
Regulatory Asset Recovery, Aurora	$/kWh	0.0050
Regulatory Asset Recovery, Markham	$/kWh	(0.0012)
Regulatory Asset Recovery, Richmond Hill	$/kWh	(0.0003)
Regulatory Asset Recovery, Vaughan	$/kWh	(0.0022)
Sentinel Lighting		
Regulatory Asset Recovery, Aurora	$/kW	2.2609
Regulatory Asset Recovery, Markham	$/kW	0.7657
Regulatory Asset Recovery, Vaughan	$/kW	0.4220
Street Lighting		
Regulatory Asset Recovery, Aurora	$/kW	0.1716
Regulatory Asset Recovery, Markham	$/kW	(0.7320)
Regulatory Asset Recovery, Richmond Hill	$/kW	(0.8406)
Regulatory Asset Recovery, Vaughan	$/kW	(1.3390)

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective November 1, 2007

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EB-2007-0074

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	1.0368
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0265
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0850

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, 2008.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

DECISION

Introduction

PowerStream Inc. ("PowerStream") is a licensed distributor of electricity providing service to consumers within its licensed service area. PowerStream 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, 2008.

PowerStream is one of over 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, PowerStream is one of the electricity distributors to have its rates adjusted for 2008 on the basis of the 2nd Generation Incentive Rate Mechanism ("IRM") process.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2008 rate adjustments (the "Guidelines") for distributors applying for rate adjustments pursuant to the IRM process.

Notice of PowerStream's rate application was given through newspaper publication in PowerStream'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. There were no intervention requests and no comments were received.

The Board issued Procedural Order No.1 on December 19, 2007, in which the Board announced that it would proceed by way of a written hearing. Procedural Order No. 1 also established a schedule for the filing of and response to interrogatories, and the filing of and response to submissions. Board staff submitted interrogatories and a submission on the application.

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

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

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2007 data published by Statistics Canada, the Board has established the price escalator to be 2.1%. The resulting price cap index adjustment is therefore 1.1%. 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. A change in the federal income tax rate effective January 1, 2008 was also incorporated into the rate model and reflected in distribution rates.

The Board also considered the reduction in Ontario capital tax and the increase in capital cost allowance (CCA) applicable to certain buildings and computers acquired after March 2007. The Board has decided that adjustments related to these items are not required, either because the changes are not of general application, or because they do not appear to be material.

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

- the specific service charges;
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery); and
- any continuing rate riders.

Accordingly, the Board is providing PowerStream with a rate model (spreadsheet) that reflects the price cap adjustments described above. PowerStream is required to review the rate model (spreadsheet) and to confirm its completeness and accuracy with the Board at the time it files its Draft Rate Order. PowerStream shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges which will reflect the Board's price cap adjustments as verified by PowerStream. PowerStream shall also provide the rate model (spreadsheet) that underpins the Tariff of Rates and Charges. Any changes to the Board's rate model (spreadsheet) shall be clearly identified and explained.

Rate Riders

When the Board approved new rates for distributors for 2006, it also approved the recovery of regulatory asset balances on a final basis. The Board approved rate riders to facilitate the recovery of the approved balances over the two remaining years of the four-year recovery period mandated by the Minister of Energy (i.e. May 1, 2004 to April 30, 2008). The rate rider(s) associated with the recovery of regulatory assets will cease on May 1, 2008 and shall be removed from the Tariff of Rates and Charges, unless a previous Board decision authorized the continuation of such riders beyond April 30, 2008. No such authorization has been previously provided by the Board for PowerStream.

PowerStream requested the approval of a one-year Regulatory Asset Recovery rate rider to dispose of the balance in account 1590 as of April 30, 2008. In its submission, Board Staff noted that the usual practice for disposing of variance and deferral accounts in the electricity sector is to use the most up-to-date audited balances, as supported by audited financial statements, plus forecast carrying charges on those balances up to the start of the new rate year. The Board accepts Staff's observation and notes that the final balance cannot be confirmed until after the current recovery period has expired (i.e. after April 30, 2008). Once the residual balance in deferral account 1590 is finalized, the residual balance will be disposed in a future proceeding. Therefore, the Board rejects this proposal.

PowerStream also proposed to dispose of the regulatory asset balances accumulated up to December 31, 2006, including interest up to April 30, 2008. The Board notes that on February 19, 2008, the Board announced an initiative for the review and disposition of commodity account 1588 (RSVA-Power). As part of this initiative, the Board will consider whether to extend this initiative to other accounts that are similar in nature, including RSVAs and RCVAs. The Board finds it more appropriate to defer this matter to this initiative. In addition, the Board finds that such a request goes beyond the spirit of a mechanistic price cap adjustment. The Board therefore denies the disposition of the regulatory asset balances accumulated up to December 31, 2006 (including interest up to April 30, 2008) in this proceeding.

PowerStream forecast that it will over-recover about $4.1 million between November 1, 2007, and April 30, 2008, as a result of the lower wholesale transmission rates that became effective on November 1, 2007. PowerStream recovers its wholesale transmission costs through its retail transmission service rates which will not be adjusted until May 1, 2008, hence the forecast over-recovery. PowerStream proposed to return this amount as part of the requested one-year rate rider discussed above. As previously noted, the Board's usual practice in the electricity sector is to use the most up-to-date audited balances, as supported by audited financial statements. The Board finds it more appropriate to defer this matter to the Deferral Account Review Initiative. Therefore the Board will not approve the disposition of the forecast retail transmission service rates over-collection in this proceeding. .

Smart Meter Rate Adder

PowerStream is one of the licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities. In its EB-2007-0573 Decision and Order dated April 12, 2007, the Board approved PowerStream's request for a smart meter rate adder of $0.73 per metered customer per month effective May 1, 2007. This rate adder was based on planned installations and operating expenses for 2007.

PowerStream is requesting that its smart meter rate adder be changed from $0.73 to $1.41 per metered customer per month effective May 1, 2008. The proposed $1.41 per metered customer per month rate adder is based on a return on and of smart metering investments (i.e. return on capital and depreciation) for the 2007 installations and on the planned 2008 installations. This proposed rate adder also incorporates the associated incremental operating expenses for 2008, including an estimate of $500,000 for the IESO meter data management/meter data repository (MDM/R) fees. The MDM/R fees have not yet been approved.

In its submission, Board staff noted, and PowerStream concurred, that any difference between this estimate and actual costs would be captured in the smart meter variance accounts. However, the Board notes that the determination of the MDM/R fees does not seem imminent. The Board therefore finds that the funding of these costs through the smart meter adder is premature and denies PowerStream's request to include the estimate of $500,000 for the MDM/R fees.

In response to a Board staff interrogatory, PowerStream calculated that the exclusion of the estimated MDM/R fees would bring its requested smart meter rate adder down to $1.21 per metered customer per month. The Board notes that PowerStream's planned smart meter expenditures in 2008 will increase as it continues its smart meter implementation program. This expenditure increase results from the fact that as the total investment in smart meter increases, so does the associated depreciation costs and the base upon which a return on capital is calculated.

The Board finds that PowerStream's planned 2008 smart meter installations will help to meet the Government's goal of installing smart meters for all Ontario customers by December 31, 2010. The Board also finds that the proposed adjustment is fair and appropriately reflects the expected increase in smart meter costs in 2008. The Board therefore approves that PowerStream's smart meter rate adder be changed to $1.21 per metered customer per month effective May 1, 2008. This funding relates strictly to smart metering investments that are within the minimum functionalities set out in Ontario Regulation 425/06. The Board also wishes to emphasize that it is not approving, as part of this proceeding, any smart metering amounts.

The $1.21 per metered customer per month rate adder is not set to guarantee costs recovery, nor is it set at a level that is deemed to be prudent. By providing advance funding, the $1.21 per metered customer per month rate adder will phase in the rate increase that could otherwise arise if the cost of the associated smart meters were brought into rate base all at once at the time of rebasing. Since a prudence review examining both substance and quantum will be conducted in due course, the Board notes that the difference between the amounts recovered through this rate adder and the related revenue requirement should continue to be captured in a variance account.

Retail Transmission Service Rates

On October 17, 2007, the Board issued its EB-2007-0759 Rate Order, setting new Uniform Transmission Rates for Ontario transmitters, effective November 1, 2007. The Board approved a decrease of 18% to the wholesale transmission network rate, a decrease of 28% to the wholesale transmission line connection rate, and an increase of 7% to the wholesale transformation connection rate. The combined change in the wholesale transmission line connection and transformation connection rates is a connection rate reduction of 5%.

On October 29, 2007, the Board issued a letter to all electricity distributors directing them to propose an adjustment to their retail transmission service (RTS) rates to reflect the new Uniform Transmission Rates for Ontario transmitters effective November 1, 2007. The objective of resetting the rates was to minimize the prospective balance in variance accounts 1584 and 1586 and also to mitigate intergenerational inequities.

PowerStream proposed to reduce its RTS – Network Service Rate by 17.8% and its RTS - Line and Transformation Connection Service Rate by 19.3% across all rate classes. These adjustments are based on a comparison of RTS revenue under existing rates and adjusted wholesale transmission costs. The Board finds that this approach is reasonable and therefore approves these adjustments. PowerStream is required to include this change in its rate model (spreadsheet) to be filed with the Board.

Implementation

PowerStream's new distribution rates are effective May 1, 2008. The Board directs that:

1. PowerStream shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges and the supporting rate model (spreadsheet) within seven (7) days of the date of this Decision. The proposed Tariff of Rates and Charges shall be filed in a Word format. The adjusted rate model shall be filed in an Excel format.

DATED at Toronto, March 17, 2008.

Original signed by

Paul Vlahos
Presiding Member

Original signed by

Paul Sommerville
Member

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0850

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. pursuant to section 78 of the Ontario Energy Board Act seeking approval to amend electricity distribution rates.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

RATE ORDER

PowerStream Inc. ("PowerStream") is a licensed distributor of electricity providing service to consumers within its licensed service area. PowerStream 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, 2008.

On March 17, 2008, the Board issued its Decision (the "Decision") regarding PowerStream's application.

The Board directed that PowerStream file with the Board a proposed Tariff of Rates and Charges reflecting the Board's Decision, within 7 days of the date of the Decision.

PowerStream has provided the Board with a proposed Tariff of Rates and Charges.
The Board is satisfied that the document accurately reflects the Decision.

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

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, 2008, for electricity consumed or estimated to have been consumed on and after May 1, 2008.

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 and is final in all respects.

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

DATED at Toronto, April 17, 2008.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix "A"
The Tariff of Rates and Charges
To The Rate Order Arising from Decision
EB-2007-0850
PowerStream Inc.

April 17, 2008

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0850

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, 2008 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2008 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2008 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2008 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.

General Service 50 to 4,999 kW – Legacy
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. Usage is measured by a time of use meter, which is a device that measures and records electrical usage during pre-specified periods of the day cumulatively over a meter reading period. This legacy classification refers to two accounts located in Markham only.

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.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0850

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	$	13.23
Distribution Volumetric Rate	$/kWh	0.0131
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	29.91
Distribution Volumetric Rate	$/kWh	0.0114
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0021
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	302.94
Distribution Volumetric Rate	$/kW	2.3627
Retail Transmission Rate – Network Service Rate	$/kW	1.8009
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8391
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 – 4,999 kW – Legacy

Service Charge	$	3,314.46
Distribution Volumetric Rate	$/kW	1.6590
Retail Transmission Rate – Network Service Rate	$/kW	1.9081
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8670
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	8,979.30
Distribution Volumetric Rate	$/kW	1.3036
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1128
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	0.9917
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0850

Unmetered Scattered Load

Service Charge (per connection)	$	14.35
Distribution Volumetric Rate	$/kWh	0.0114
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.01
Distribution Volumetric Rate	$/kW	6.0842
Retail Transmission Rate – Network Service	$/kW	1.3762
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7115
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.84
Distribution Volumetric Rate	$/kW	3.4686
Retail Transmission Rate – Network Service Rate	$/kW	1.3624
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6524
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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)

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

EB-2007-0850

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	1.0368
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0265
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Schedule 4

Accounting Orders

PowerStream has no accounting orders from the OEB.

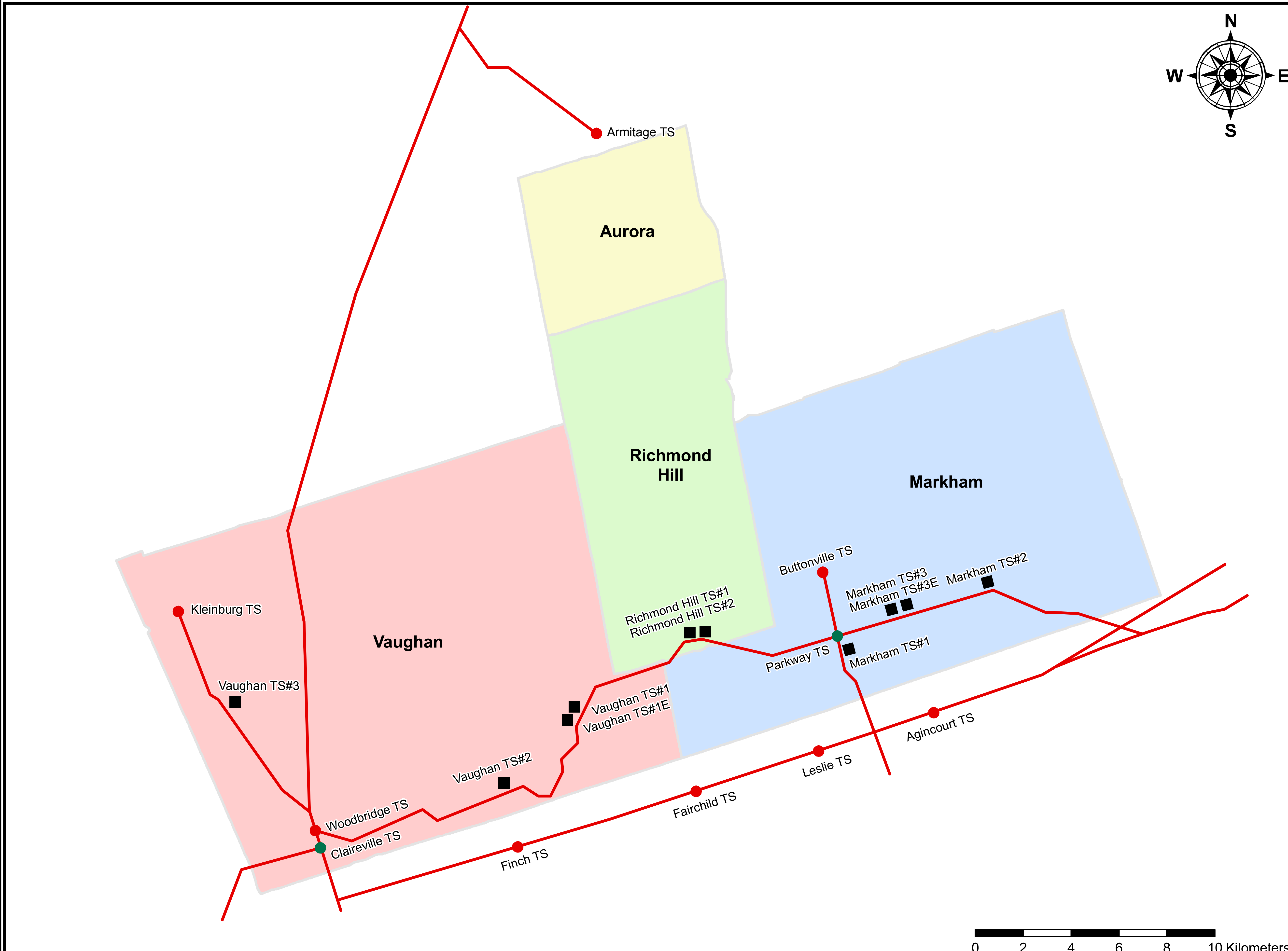
Schedule 5

LIST OF NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

PowerStream Inc. is in compliance with Uniform System of Accounts.

Schedule 6

MAP OF DISTRIBUTION SYSTEM



TRANSFORMER STATION DETAILS

Agincourt TS
107 Milliken Road
1 feeder

Buttonville TS
3315 16th Avenue
12 feeders

Claireville TS
7290 Martin Grove Road
no feeders

Fairchild TS
5760 Yonge Street
2 feeders

Finch TS
2150 Finch Avenue West
2 feeders

Kleinburg TS
1131 Cold Creek Road
2 feeders

Leslie TS
5655 Leslie Street
2 feeders

Markham TS 1
3430 14th Avenue
8 feeders

Markham TS 2
7970 Highway 48
8 feeders

Markham TS 3 and TS 3E
7932 Kennedy Road
8 feeders and 8 feeders

Parkway TS
Unknown
no feeders

Richmond Hill TS 1 and TS 2
160 Highway 7 East
12 feeders and 10 feeders

Vaughan TS 1 and TS 1E
8000 Dufferin Street
12 feeders and 12 feeders

Vaughan TS 2
1 Century Place
9 feeders and 2 Toronto Star feeders

Vaughan TS 3
6531 Rutherford Rd
10 feeders

Woodbridge TS
5839 Highway 7 West
4 feeders

LEGEND

- 230 kV Transmission Lines
- Hydro One 500kV Transformer Stations
- Hydro One 230kV Transformer Stations
- PowerStream 230kV Transformer Stations
- Town of Aurora
- Town of Markham
- Town of Richmond Hill
- City of Vaughan

Power Stream
YOUR CURRENT CONNECTION

Figure 1
Transformer Stations Supplying PowerStream

DRAWN BY :	Richard Brown
CHECKED BY :	Irv Klajman
APPROVED BY :	Irv Klajman
DATE :	June 19, 2006
REVISION NUMBER :	1

PowerStream GIS Department

Schedule 7

LIST OF NEIGHBOURING UTILITIES

PowerStream Inc.
List of Neighbouring Utilities

To the East:

- Veridian Connections Inc.
- Whitby Hydro Electric Corporation

To the South:

- Toronto Hydro-Electric System Limited

To the West:

- Hydro One Brampton Networks Inc.
- Enersource Hydro Mississauga Inc.

To the North:

- Newmarket Hydro Ltd.
- Hydro One Networks Inc.

Schedule 8

EXPLANATION OF HOST OR EMBEDDED UTILITIES

PowerStream Inc. does not have Host or Embedded Utilities.

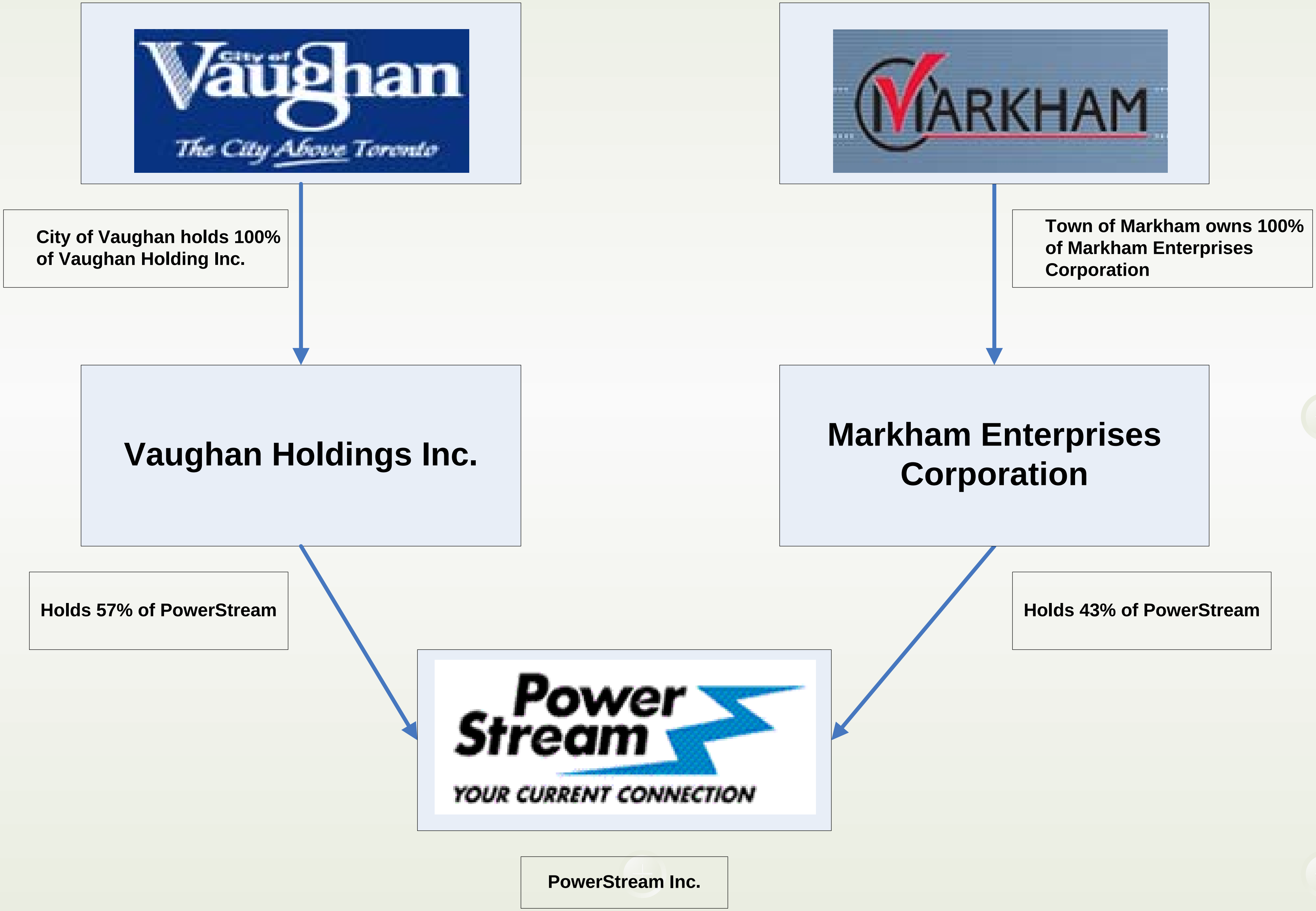
Schedule 9

UTILITY ORGANIZATION CHART

PowerStream Inc.
Organization Chart as of May 15, 2008

Schedule 10

CORPORATE ENTITIES RELATIONSHIP CHART


City of Vaughan
The City Above Toronto
MARKHAM
City of Vaughan holds 100% of Vaughan Holding Inc.
Town of Markham owns 100% of Markham Enterprises Corporation
Vaughan Holdings Inc.
Markham Enterprises Corporation
Holds 57% of PowerStream
Holds 43% of PowerStream
Power Stream
YOUR CURRENT CONNECTION
PowerStream Inc.

Schedule 11

Planned Changes in Organization/Operational Structure

PowerStream Inc. is not planning changes in Organization/Operational Structure unless the merger with Barrie Hydro proceeds.

Schedule 12

Status of Board Directives

YOUR CURRENT CONNECTION

July 28th, 2008

Mr. Bill Cowan
Chief Regulatory Auditor
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Mr. Cowan:

Re: PowerStream (Aurora) Capital Work – July 31st Quarterly Report

Please find enclosed the Quarterly Report on PowerStream (Aurora)'s capital work that was approved by the Board in the 2006 EDR Decision and Order (RP-2005-0020/EB-2005-0337).

If you have any questions or require further information, please contact John Mulrooney, Director of Engineering Standards and Design at (905) 532-4608, or me at (905) 532-4527.

Yours truly,

[Original Signed By]

Sarah Griffiths
Manager of Regulatory Affairs

2006 SPECIFIED PROJECTS IN WHICH AURORA RECEIVED A SPECIAL RATE ADJUSTMENT									
Number	**PROJECT DESCRIPTION**	**2006 STATUS**	**2006 EDR (Aurora) Cost (000)**	**2006 Spending (000)**	**Future Status**	**2007 Spending (000)**	**Status at the end of 2007/Q1 2008**	**Status as of July 2008**	**2008 Spending (000)**
1	Rebuild 44kv line on Industrial Pkwy S from Police to Engelhard	Completed in 2006.	$169	$122	N/A	$0	N/A	N/A	$0
2	Build new 13.8kV cct. on Vandorf from Bayview Ave to Leslie St	Deferred due to PowerStream acquisition of Aurora Hydro	$245	$0	Rebuild existing pole line to accommodate 1-44kV cct, 1-28kV cct and upgrade single phase-8kv cct to three phase 13.8kV cct. To be completed in Q3 2008	$132	Design/Approval stage and purchasing of materials	Work order issued for construction on March 17, 2008	$554
3	Pole Testing and Replacement	48% complete	$54	$26	Completed year end 2007	$28	Completed	Completed	N/A
4	Install 13.8kV load interrupter switches	27% complete	$30	$8	Completed year end 2007	$22	Completed	Completed	N/A
5	Install 44kV load interrupter switches	In 2007 Capital Plan	$26	$0	Completed year end 2007	$26	Completed	Completed	N/A
6	Install spaced aerial line on Yonge St. from Mark to Catherine	In 2007 Capital Plan	$75	$0	To be completed in Q3 2008	$0	Design stage	Work order issued for construction on May 29, 2008	$3
7	Upgrade spaced aerial line on Wells from Wellington to Mosley	In 2007 Capital Plan	$63	$0	To be completed in Q4 2008	$0	Design stage	Work order to be issued for construction on Sept. 5, 2008	$0
8	Replacement of 1/0 u/g single phase on Wells from Centre to Wellington	In 2007 Capital Plan	$86	$0	To be completed in Q4 2008	$0	Design stage	Work order to be issued for construction on Sept. 5, 2008	$0
9	Upgrade 1/0 u/g feeder tie on Wells St	In 2007 Capital Plan	$63	$0	To be completed in Q4 2008	$0	Design stage	This project has been incorporated with #7	$0
			$811	**$156**		**$208**			**$557**

*Project scope increased along with costs.

August 31st, 2007

Mr. Bill Cowan
Chief Regulatory Auditor
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Mr. Cowan:

Re: PowerStream (Aurora) Capital Work – Progress Report and Updated Plan

In response to your letter dated July 30th, 2007, PowerStream Inc. ("PowerStream") presents the progress report and updated plan to the Ontario Energy Board ("the Board") on PowerStream (Aurora)'s capital work that was approved by the Board in the 2006 EDR Decision and Order (RP-2005-0020/EB-2005-0337).

As outlined in the Aurora Hydro Connections Limited ("Aurora Hydro")'s 2006 EDR Decision and Order, in its 2006 EDR application Aurora Hydro made a Tier 2 adjustment to Rate Base of $811,000 on the basis that it experienced negative returns in 1999. Due to the impact of the methodology used in the 1999 rate setting process, and the resulting ongoing shortfall in revenues, Aurora Hydro was able to continue its maintenance programs however unable to complete all of its capital programs.

The Board accepted the Tier 2 adjustment as a reasonable request and directed Aurora Hydro, in accordance with the EDR Handbook, to report to the Board on the progress and completion of the Tier 2 projects. The 2006 EDR handbook also identified a variance account to track Tier 2 expenditures, and Aurora Hydro's application (paragraph 5) requested an order to establish a variance account. However, while the Board approved the Tier 2 adjustment, the issue of a variance account was not addressed or approved. At the time of the decision neither Aurora Hydro nor PowerStream took note that a variance account was required by the Handbook or absent in the decision. Unfortunately, it was not until your letter that PowerStream was reminded of a variance account. As such, we have not treated any expenditures separately.

The capital projects outlined in the Aurora Hydro application were subsumed into the overall integrated PowerStream project plans. The projects outlined in Aurora Hydro's original application are still required but the timing has changed, and a reprioritization has occurred with their integration into the overall system plan. This reprioritization has led to other capital work that was unplanned at the time of the Aurora Hydro rate application, being completed in the Aurora service territory.

All of the original Tier 2 projects have been identified in the 2006/2007 capital plans and will largely be completed by the end of 2007. PowerStream will send a confirmation report at a later date confirming their completion status.

The progress report on the Tier 2 capital projects outlined in the Aurora Hydro application, including the revised timeline for completion is attached.

If you have any questions or require further information, please contact John Mulrooney, Director of Engineering Standards and Design at (905) 417-6969 or me at (905) 417-6900 ext.8138.

Yours truly,

(original signed by Sarah Griffiths)

Sarah Griffiths
Manager of Regulatory Affairs

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

July 30, 2007

Ms. Paula Conboy
Director of Regulatory and Government Affairs
PowerStream Inc.
2800 Rutherford Road
Vaughan, Ontario
L4K 2N9

Dear Ms. Conboy:

Re: Quarterly Reports – PowerStream (Aurora) Capital work

This is a request to send progress reports to the Board on PowerStream (Aurora)'s capital work, as approved by the Ontario Energy Board (the "Board") in its 2006 EDR Decision and Order (proceeding RP-2005-0020 / EB-2005-0337). No reports have been received by the Board to date.

Section 3.3 of the 2006 EDR Handbook states that Tier 2 adjustments are subject to monitoring requirements. These requirements include the filing of quarterly reports with the Board during the period of the approved expenditures, confirming that they have taken place as stated in your filing, or if not, providing an explanation for the variance and your revised plans.

I am aware that the Board also directed PowerStream (Aurora) to report on the progress and completion of the Tier 2 projects in its next rates application, but quarterly status reports are still expected.

Please provide a required progress report to my attention covering the period from May 1, 2006 to the quarter ending June 30, 2007 by August 31st. For each future quarter, please send progress reports to my attention within 30 days of each quarter end, coincident with the reporting due date for other Board requirements.

If you have any questions or concerns, please contact me.

Yours truly,

Bill Cowan, P.Eng., C.A.
Chief Regulatory Auditor
Phone: (416) 440-7648

Schedule 13

COMPANY POLICIES AND PROCEDURES ON ELECTRICITY SERVICES AND SERVICE CHARGES

Conditions of Service

Aurora - Markham - Richmond Hill - Vaughan

PowerStream Inc.
161 Cityview Boulevard
Vaughan, Ontario, Canada
L4H 0A9

Version 2.1
Effective: September 27, 2007

REVISION HISTORY

Revision Number	Revision Date	Author	Reason for Revision
1.0	March 1, 2006	Engineering Standards & Design	Draft Submission
1.1	May 30, 2006	Engineering Standards & Design	Submission to Ontario Energy Board
2.0	July 16,2007	Engineering Standards & Design	Draft - Changes in the Distribution System Code
2.1	September 27,2007	Engineering Standards & Design	Submission to Ontario Energy Board

The Distribution System Code (DSC) requires that every Distributor produce its own Conditions of Service (COS) document. The purpose of this document is to provide a means for communicating the types and level of service available to the Customers within the PowerStream Inc. service area. The DSC requires that the COS be readily available for review by the general public. In addition, the most recent version of the document must be provided to the Ontario Energy Board (OEB), which in turn will retain it on file for the purpose of facilitating dispute resolutions in the event that a dispute cannot be resolved between the Customer and its local distributor.

This document follows the form and general content of the COS template appended to the DSC and included in this COS as Appendix A. The template outlines the minimum requirements. However, as suggested by the DSC, PowerStream Inc. has expanded on the contents to encompass local characteristics and other specific requirements.

The Distribution Activities (General) section contains references to services and requirements that are common to all Customer classes. This section covers items such as Rates, Billing, Deposits, Hours of Work, Emergency Response, Power Quality, Available Voltages and Metering.

The Customer Class Specific section contains references to services and requirements specific to the respective Customer class. This section covers items such as Service Entrance Requirements, Delineation of Ownership, Special Contracts, etc.

Other sections include the Glossary of Terms and Appendices and References.

Subsequent changes will be incorporated with each submission to the OEB.

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TABLE OF CONTENTS

SECTION 1. INTRODUCTION

1.1 Identification of Distributor and Service Area

PowerStream Inc. (PowerStream) referred to herein is a corporation incorporated under the laws of the Province of Ontario to "distribute" electricity and to provide services to assist the government in achieving its goal in electricity conservation.

PowerStream is licensed by the Ontario Energy Board ("OEB") to supply electricity to "Customers" and to operate distribution facilities within its licensed Distribution Service Area as described in the OEB Distribution License #ED-2004-0420 issued to PowerStream on August 30, 2004. This "Conditions of Service" (COS), as prescribed by the "Distribution System Code" (DSC), outlines PowerStream's operating practices and "connection" policies, the obligations of PowerStream's Customers and the minimum standards of service PowerStream's Customers can expect in accordance with the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*.

PowerStream may only operate within its licensed territory as defined in its Distribution License. The defined territory is the City of Vaughan, the Town of Aurora, the Town of Markham and the Town of Richmond Hill. Refer to Appendix C – "Service Area" Map. The service area is subject to change with the OEB's approval.

Nothing contained in this COS or in any contract for the supply of electricity by PowerStream shall prejudice or affect any rights, privileges, or powers vested in PowerStream by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any "regulations".

1.1.1 Distribution Overview

PowerStream distributes electrical "energy" through its three phase "distribution systems" at nominal operating voltages of 44,000 volts (V), 27,600 V, 13,800 V and 8,320 V. Feeders are arranged to run radial out from transformer substations owned by PowerStream and Hydro One Networks Inc. Open points exist between feeders and this determines the feeder geographical coverage. These feeders directly supply pole mounted, pad mounted or vault type distribution transformers that reduce the operating voltage to Customer levels.

1.2 Related Codes and Governing Laws

The supply of electricity or related services by PowerStream to any Customer shall be subject to various laws, regulations, and codes, including the provisions of the latest editions of the following documents:

- *Electricity Act, 1998, S.O. c15 Schedule A*
- *Ontario Energy Board Act, 1998 S.O. c15 Schedule B*
- Electricity Distribution Licence
- Independent Electricity Market Operator - Market Rules
- Affiliate Relationship Code for Electricity Distributors and Transmitters
- Transmission System Code
- Distribution System Code
- Retail Settlement Code
- Standard Service Supply Code
- Ontario Electrical Distribution Safety Code
- Ontario Regulation 22/04
- *Environmental Protection Act*
- Electricity Retailer Code of Conduct
- *Personal Information Protection and Electronic Documents Act, 2000, C.5*
- *Municipal Freedom of Information and Protection of Privacy Act, 1990, R.S.O.*
- *Electricity and Gas Inspection Act*
- Any other obligation or requirement as prescribed by legislation or regulations

In the event of a conflict between this document and the Distribution License or regulatory codes issued by the OEB, or the *Energy Competition Act, 1998* provisions, the Distribution License and associated regulatory codes shall prevail in the order of priority established by the OEB.

Customers and their agents must plan and design the required electricity service with adherence to all applicable "provincial" and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. Without limiting the foregoing, the work shall be conducted in accordance with the latest edition of the *Ontario Occupational Health and Safety Act* (OHSA); the Regulations for Construction Projects and the Electrical Utility Safety Rules published by the Electrical and Utilities Safety Association of Ontario Incorporated and dated August 2004.

1.3 Interpretations

In this COS, unless the context otherwise requires:

- Headings, capitalization, paragraph numbers and underlining are for convenience only and do not affect the interpretation of this COS;
- Words referring to the singular include the plural and vice versa; and
- Words referring to a gender include any gender...

Should PowerStream deem that the Customer is required to enter into an Offer To Connect (OTC) with PowerStream, and should the terms and conditions in the OTC conflict with this COS, the OTC shall govern.

Should a conflict exist within this COS, the hierarchy shall be:

- Standards (Drawings); followed by
- Appendices; followed by
- Text

1.4 Amendments and Changes

The provision of this COS and any amendments made from time to time form part of any contract made between PowerStream and any connected Customer, "Retailer", or "Generator", and this COS supersedes all previous versions of this document, oral or written, of PowerStream or any of its predecessor "municipal" electric utilities as of its effective date.

In the event of changes to this COS, PowerStream will issue a notice with and/or on the Customer's bill. In dealing with some sections of the COS, PowerStream may also issue a public notice in a local newspaper.

The Customer is responsible for contacting PowerStream to ensure that the Customer has the current version of this COS. PowerStream shall provide one copy per revision for each Person that requests it. The current version of the document is also posted on the PowerStream website and can be downloaded from www.powerstream.ca.

1.5 Contact Information

To report a power outage, electrical "emergency" or to hear when power will be restored, the PowerStream Outage Communication Service is available 24 hours a day:

- Toll Free 1-877-777-3810

PowerStream can be contacted during normal business operating hours of 8:00 a.m. to 4:30 p.m., Monday through Friday, excluding holidays:

- Toll Free 1-877-963-6900
- Markham 905-477-3810
- Vaughan 905-417-6900

Or such other numbers as PowerStream may advise through its invoices or otherwise.

- By Mail: PowerStream Inc.
  P.O. Box 3700
  Concord, Ontario L4K 5N2

- Website: www.powerstream.ca

1.6 Customer Rights

PowerStream shall only be liable to a Customer and a Customer shall only be liable to PowerStream for any damages that arise directly out of wilful misconduct or negligence:

- of PowerStream in providing "distribution services" to the Customer;
- of the Customer in being connected to PowerStream's distribution system; or
- of PowerStream or Customer in meeting their respective obligations under this COS, their licenses and any other applicable law.

Notwithstanding the above, neither PowerStream nor the Customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

The Customer shall indemnify and hold harmless PowerStream, its directors, officers, employees and agents from any claims made by any third parties in connection with the construction and installation of a Generator by or on behalf of the Customer.

1.7 Distributor Rights

1.7.1 Access to Customer Property

PowerStream shall have access to Customer property in accordance with the *Electricity Act 1998, Section 40.*

1.7.2 Safety of Equipment

The Customer will comply with all aspects of the Ontario Electrical Safety Code (OESC) with respect to ensuring that equipment is properly identified and connected for metering and operating purposes and will take whatever steps necessary to correct any deficiencies, in particular cross wiring situations, in a timely fashion. If the Customer does not take such action within a reasonable time, PowerStream may disconnect the supply of power to the Customer.

The Customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the operation of distribution lines, endanger PowerStream equipment, interfere with the proper and safe operation of PowerStream's facilities or adversely affect compliance with any applicable legislation in the sole operation of PowerStream.

The Customer shall not use or interfere with the facilities of PowerStream except in accordance with a written agreement with PowerStream. The Customer must also grant PowerStream the right to seal any point where a connection may be made on the line side of the metering equipment.

Subject to any prior agreements, Customers are responsible for all initial and continuing tree trimming and tree and brush removal for all new and existing "secondary services", "primary services", and substations on a Customer's property. Clearances shall conform to the OESC. In order to complete work safely, PowerStream shall isolate the Customer's service during normal working hours at no charge.

If any of PowerStream's facilities or equipment are damaged, destroyed by fire or any other cause other than ordinary wear and tear, the Customer shall pay PowerStream the value of said PowerStream facilities and equipment or the cost of repairing or replacing the same.

1.7.3 Operating Control

The Customer will provide a convenient and safe place, satisfactory to PowerStream, for installing, maintaining and operating PowerStream's equipment in, on, or about the Customer's premises. PowerStream assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer's premises or approaches thereto, or action, omission or occurrence beyond its control, or negligence of any Customers over whom PowerStream has no control.

Unless an employee or an agent of PowerStream, or other Customer lawfully entitled to do so, no Customer shall remove, replace, alter, repair, inspect or tamper with PowerStream's equipment.

Customers will be required to pay the cost of repairs or replacement of PowerStream's equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

The physical location at which the "Distributor's" responsibility for operational control of distribution equipment including "connection assets" ends on the Customer's premises is defined by the DSC as the "operational demarcation point".

Operation and "operating control" of high voltage equipment at a Customer's premises shall be as per an Operating Agreement entered into with the Customer.

1.7.4 Defective Customer Electrical Equipment

The Customer will be required to repair or replace any equipment owned by the Customer that may affect the integrity or reliability of PowerStream's distribution system. If the Customer does not take such action within a reasonable time, PowerStream may disconnect the supply of power to the Customer. PowerStream's policies and procedures with respect to the "disconnection" process are further described in Section 2.2 of this COS.

1.7.5 Customer's Physical Structures

Depending on the "ownership demarcation point", construction, repairs and maintenance of all civil works on "private property" owned by the Customer, including such items as transformer vaults, "transformer rooms", transformer pads, manholes, cable pull rooms, underground conduits, bollards, fences or other structures, shall be the responsibility of the Customer. All civil work on private property must be inspected and accepted by PowerStream and the "Electrical Safety Authority" (ESA). The Customer is responsible for the maintenance and safe keeping conditions, satisfactory to PowerStream, of its structural and mechanical facilities located on private property.

1.8 Disputes

Any dispute between Customers or Retailers and the Distributor shall be settled according to the dispute resolution process specified in the Distribution Licence.

To resolve disputes PowerStream will follow the terms of the Distribution Licence as follows:

(i) establish proper administrative procedures for resolving complaints by Customers and other market participants regarding service provided under the terms of this License;
(ii) publish information which will facilitate its Customers accessing its complaints resolution process;
(iii) refer unresolved complaints and subscribe to an independent third party complaints resolution agency which has been approved by the OEB;
(iv) make a copy of the complaints resolution procedure available for inspection by members of the public at each of the Licensee's premises during normal business hours;
(v) give or send free of charge a copy of the procedure to any Customer who reasonably requests it; and
(vi) keep a record of all complaints, whether resolved or not, including the name of the complainant, the nature of the complaint, the date resolved or referred and the result of the dispute resolution.

Once PowerStream receives a complaint or dispute from a Customer, a PowerStream representative will initiate contact with the Customer, as well as research, investigate and follow up on the complaint to attempt to reach a resolution. If PowerStream and the Customer cannot reach a mutual agreement within ninety (90) calendar days of PowerStream receiving the complaint, PowerStream will refer the complaint to an independent third party resolution agency, which has been approved by the OEB. Until the OEB approves an independent third party complaints resolution agency, such complaints will be referred to the OEB, which has assumed this role.

1.9 Force Majeure

If a "Force Majeure" prevents either party from performing any of its obligations under this COS, that party shall:

- other than Force Majeure related to acts of God, promptly notify the other party of the Force Majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practical;
- not be entitled to suspend performance of any of its obligations under this COS to any greater extent or for any longer time than the Force Majeure event requires it to do so;
- use its best efforts to mitigate the effect of the Force Majeure event, remedy its inability to perform, and resume full performance of its obligations;
- keep the other party continually informed of its efforts;
- other than for Force Majeure events related to acts of God, provide written notice to the other party when it resumes performance of any obligations affected by the Force Majeure event; and
- if the Force Majeure event is a strike or a lockout of PowerStream's employees or authorized representatives, PowerStream shall be entitled to discharge its obligations to notify its Customers in writing by means of placing an ad in the local newspaper.

PowerStream shall not be liable for any delay or failure in the performance of any of its obligations under this COS due to any events or causes beyond the reasonable control of PowerStream, including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes.

- End of Section -

SECTION 2. DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connection Process and Timing

Under the terms of the DSC, PowerStream has the obligation to either connect or to make an OTC to any Customer that lies in its service area. If the Customer is not the registered landowner, PowerStream must have the written consent of the registered landowner in order to enter into any agreement. Please refer to sections 2.1.7.6 and 2.1.7.7 for further clarification. In the case where a lessee is executing the OTC, they can only do so with a letter of consent signed by the property owner.

The Customer or its authorized representative shall consult with PowerStream concerning the availability of supply, the "supply voltage", service location, metering, and any other project-related details. These requirements are separate from and in addition to those of the ESA. The Customer or its authorized representative shall apply for new or upgraded "electric service" and temporary power service in writing. The Customer is required to provide PowerStream with sufficient lead-time in order to ensure:

- the timely provision of supply to new and upgraded premises; or
- the availability of adequate capacity for additional loads to be connected in existing premises.

PowerStream shall respond within fifteen (15) calendar days of a written receipt of a request for connection. The response shall include an application information form, hereafter called the Application.

The Customer's completed Application shall include:

- the approximate date that the Customer requires the electrical service,
- one copy of all relevant project drawings (if required). Where the Customer requires an approved copy to be returned, two copies of all plans must be submitted. All drawings must be submitted to PowerStream with adherence to PowerStream's Standards,
- characteristic of supply,
- proof of legal land ownership, and
- the due date that PowerStream's civil construction drawings are required to co-ordinate with site construction.

Provided all required information for the Application has been submitted to the satisfaction of PowerStream and none of the conditions of Connection Denial in Section 2.1.3 apply, PowerStream shall make an OTC within sixty (60) calendar days. PowerStream, in its discretion, may require a Customer, Generator or Distributor to enter into an OTC with PowerStream including terms and conditions in addition to those expressed in this COS.

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. PowerStream will notify the Customer of any extended lead times.

New residential subdivisions or multi-unit developments involving the construction of new city streets and roadways are treated as Non-Residential Class Customers and involve capital contribution for "Expansion" work, in addition to any applicable Connection Charges. Should the Economic Model identify a shortfall for the Expansion, the "Developer" has a choice of either completing the portion of plant not yet connected to PowerStream's Distribution System or have PowerStream complete this work in accordance with Section 3.3 of the DSC, titled Alternate Bids. The Customer will not be allowed to complete construction work on PowerStream's existing Distribution System.

New residential subdivisions or multi-unit complexes not involving new city streets and roadways, but only private property, will follow the general terms and conditions for Connection Charges and Capital Contribution for the appropriate General class Customers.

The Developer is required to enter into an OTC with PowerStream and to pay PowerStream the deposit(s) for ordering of equipment and associated design and construction work for the installation of the proposed underground electrical distribution system. This amount will be paid concurrently with the signing of the OTC. Refer to Section 2.1.2 of this COS.

PowerStream must approve all design work including service locations and trench routes.

Refer to References - Commercial / Industrial New Services Offer to Connect and Residential Subdivision Offer to Connect.

2.1.1 Building that Lies Along

For the purpose of this COS, "lies along" means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where PowerStream has distribution facilities of the appropriate voltage and capacity.

Under the terms of the DSC, PowerStream has the obligation to connect (under *Section 28 of the Electricity Act, 1998*) a "building" or facility that lies along its distribution line, provided:

(i) the building can be connected to PowerStream's distribution system without an expansion or "enhancement" to the distribution system; and
(ii) the service installation meets the conditions listed in this COS of PowerStream that owns and operates the distribution line; and
(iii) the location of the Customer's service entrance equipment will be subject to the approval of PowerStream and the ESA.

A Customer may be required to enter into an OTC with PowerStream, if PowerStream believes that the Customer's load has characteristics that require an explicit document to describe the relationship between PowerStream and the Customer.

2.1.2 Expansions/Offer To Connect

Under the terms of the DSC, PowerStream is required to make an OTC, if, in order to connect a Customer, PowerStream must construct new, or increase the capacity of, existing distribution system facilities deemed an "Expansion" to its system. In making an OTC, PowerStream shall include, without limitation, the following components, as applicable:

- "Basic Connection Charge",
- "Variable Connection Charge",
- System Enhancement Charge (Upstream Charge),
- Capital Contributions,
- Securities.

The cost associated with the Expansion is to be fair and reasonable and is in addition to any Basic and/or Variable Connection Charges as identified in Section 3 of this COS.

To cover the capital and on-going maintenance costs of the Expansion project, PowerStream will perform an economic evaluation as outlined in the DSC Appendix B Methodology and Assumptions for an Economic Evaluation, Appendix B of this COS, (Economic Model) to determine any cost sharing of the Expansion between PowerStream and the Customer.

At the discretion of PowerStream, the capital costs for the Expansion may include incremental costs associated with the full use of PowerStream's existing spare facilities or equipment, which may result in an adverse impact to future Customers. The Economic Model will be based on the Customer's proposed load.

In performing the economic evaluation, should the Net Present Value (NPV) of the cost and revenues associated with the Expansion be less than zero (i.e. negative), a capital contribution by the Customer in the amount of the shortfall is required.

The Customer has the option to seek alternative bids for this Expansion work from PowerStream approved contractors. PowerStream may charge a Customer that chooses to pursue an alternative bid any costs incurred by PowerStream associated with the Expansion project, including but not limited to the following:

- Costs for additional design, engineering, or installation of facilities required to complete the project in addition to the original OTC;
- Costs for inspection or approval of the work performed by the contractor hired by the Customer.

2.1.2.1 Capital Contributions

PowerStream is required under the DSC to contribute to the Customer's cost of the Expansion in relation to the project. The amount of the contribution shall be determined by the Economic Model, which considers the 25-year revenue stream to PowerStream for electric loads connected on the Lands in the first five years following the date of initiation of energization as certified in writing from PowerStream (referred to herein as the "Connection Period").

PowerStream will include a preliminary summary of the economic evaluation with its OTC. This calculation will be based on the Customer's estimate of load energization throughout the connection period and provides an estimate of the project cost sharing between the Customer and PowerStream.

The Developer shall completely fund the capital cost of the Expansion project including payment of Upstream Charges. Upstream charges are charges designed to pay for new facilities and/or reinforcements, which increase the system capacity of PowerStream's distribution on the utility's side of the ownership demarcation line.

On each anniversary of energizing the project throughout the Connection Period, PowerStream will run the Economic Model using the actual connected load for each year. PowerStream will pay, to the Customer, any monies owed based on, and in accordance with, the results of the economic model. Payments under the Economic Model end when either all of the electrical loads relating to the Lands are connected or at the end of the Connection Period.

2.1.2.2 Supply Agreement and Securities

Refer to the "agreements" in the References section of this COS.

2.1.3 Connection Denial

The DSC provides for the ability of PowerStream to deny connection to its distribution system by an applicant. PowerStream is not obligated to connect a building within its service area if the connection would result in any of the disconnection circumstances as set out in Section 2.2 of this COS.

Should the application be incomplete or any of the conditions of connection denial apply, PowerStream's response shall indicate this accordingly. The Customer shall have thirty (30) calendar days from the date of PowerStream's response to complete the application and/or remove the connection denial condition, failing which the application shall be null and void. Should the Customer complete the application and/or remove the connection denial condition within the thirty (30) calendar days, PowerStream shall make an OTC within sixty (60) calendar days of the date of receipt of the completed provision of required information.

The Customer may be denied connection with PowerStream if the requested service is within another Distributor's service territory and PowerStream does not wish to provide service.

2.1.4 Inspections Before Connections

Upon request, PowerStream shall, if able, locate without charge, all PowerStream-owned secondary and primary underground cables. If PowerStream is unable to locate an underground cable, PowerStream shall provide a service disconnection and reconnection during normal working hours without charge. PowerStream shall charge for locating underground cable outside normal working hours, other than in an Emergency situation.

All Customer electrical installations shall meet the requirements of the OESC and be inspected and approved by the ESA. All Customer electrical installations must also meet PowerStream Standards and inspection requirements. PowerStream requires notification from the ESA of their approval prior to the energization of a Customer's supply of electricity.

Services that have been disconnected for the purposes of upgrade or change, or services that have been altered subsequent to ESA approval, must be re-inspected and approved by the ESA prior to the energization of a Customer's supply of electricity.

"Temporary services", typically used for construction purposes, must be approved by the ESA prior to energization.

Customer owned substations, primary "duct banks", transformer rooms, vaults and pads must be inspected by the ESA.

2.1.5 Relocation of Plant

When requested to relocate distribution plant, PowerStream will exercise its rights and discharge its obligations in accordance with existing acts, by-laws and regulations including the *Public Service Works on Highways Act*, formal agreements, easements and common law. In the absence of existing arrangements, PowerStream is not obligated to relocate the plant. However, PowerStream shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner shall include a response to the requesting party that explains the feasibility or infeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

2.1.6 Easements

The Customer shall provide to PowerStream, free from all encumbrances, and in a form satisfactory to PowerStream acting reasonably, those easements required by PowerStream for the construction and maintenance of the electrical plant.

PowerStream will request the Customer to provide an easement, which will be registered against title to the property, when electrical plant and/or equipment installation, repair, replacement, operation or maintenance requires access over private property or municipal lands. The Customer will prepare, at its cost, any required reference plan to the satisfaction of PowerStream.

2.1.7 Contracts

2.1.7.1 Contract for New or Upgraded Service

PowerStream shall only connect a Building for a new or modified supply of electricity upon receipt by PowerStream of a completed and signed OTC or "Service Layout" in a form acceptable to PowerStream, payment to PowerStream of any applicable connection charge, and an inspection and approval by the ESA of the electrical equipment for the new service, and agreed to be bound by all of the terms in the contract.

2.1.7.2 Implied Contract

In all cases, notwithstanding the absence of a written contract, PowerStream has an implied contract with any Customer that is connected to PowerStream's distribution system and receives distribution services from PowerStream. The terms of the implied contract are embedded in this COS, the "Rate Handbook", PowerStream's "rate" schedules, PowerStream's Distribution Licence, and the DSC, as amended from time to time.

Any Customer or Customers who take or use electricity from PowerStream shall be liable for payment for such electricity. Any implied contract for the supply of electricity by PowerStream shall be binding upon the heirs, administrators, executors, successors or assignees of the Customer or Customers who took and/or used electricity supplied by PowerStream.

2.1.7.3 Special Contracts

Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- Operating
- Maintenance (Customer-owned facilities)
- Non-permanent Structures
- Special Occasions
- Construction Sites
- Mobile Facilities
- Electrical Plant – (Subdivisions, Condominiums, Commercial/Industrial & Service Layouts)
- Generation

2.1.7.4 Payment by Building Owner

The owner of a building is responsible for paying for the supply of electricity by PowerStream to the owner's building, except for any supply of electricity to the Building by PowerStream in accordance with a written request or other means acceptable by PowerStream, for electricity by an occupant(s) of the Building.

A building owner wishing to terminate the supply of electricity to its building must notify PowerStream in writing. Until PowerStream receives such written notice from the building owner, the building owner or the occupant(s), as applicable, shall be responsible for payment to PowerStream for the supply of electricity to such building. PowerStream may refuse to terminate the supply of electricity to an owner's building when there are occupant(s) in the building (i.e. during certain periods of the winter).

PowerStream shall not terminate the supply of electricity when requested by a building owner for the purpose of evicting a "tenant" contracted with PowerStream for the supply of electricity.

2.1.7.5 <u>Opening and Closing of Accounts</u>

Customers who wish to open an account for the supply of electricity by PowerStream shall notify PowerStream by phone, fax, mail, PowerStream's website or other means acceptable to PowerStream. Such notification shall be provided a minimum of three "business days" prior to the opening of an account.

A Customer who wishes to close an account with PowerStream (i.e. because the Customer moves to another location, or otherwise) must notify PowerStream by phone, fax, mail, PowerStream's website or other means acceptable to PowerStream. Such notification shall be provided a minimum of three business days prior to the closing of an account. Until PowerStream receives such notice from the Customer or its authorized Retailer, the Customer shall be responsible for payment to PowerStream for the supply of electricity to the Customer. In the event a Customer wishes to close an account where a Retailer is involved, such closing shall be governed by any applicable regulatory code such as, but not limited, to the Retail Settlement Code (RSC).

2.1.7.6 <u>Tenant/Occupier Customer</u>

Where a new Customer is not the Owner of a building, premises or property to which electricity is requested to be supplied the new Customer shall upon request provide to PowerStream a copy of the lease or agreement permitting occupation of the Building premises or property; and comprehensive contact information concerning the landlord and/or Owner of the property, whichever the case may be a duly executed confirmation acknowledgement and agreement is required from the Owner as set out in Section 2.1.7.7.

Failing this, the Owner of the building, premises or property shall be required to open the new account directly with PowerStream.

2.1.7.7 Owner Liability For Tenant or Occupier

Building Owners are responsible for notifying PowerStream of any changes in tenancies. Failing such notification the account will be placed in the name of the owner. PowerStream reserves the right to recover from a building owner any charges for supply of electricity resulting from their failure to notify PowerStream of any changes in occupancy such as vacancies, evictions, lock-outs or otherwise, from the date of the change in occupancy.

Where a tenant/occupier has terminated their account for the supply of electricity with PowerStream the account will automatically transfer to the Owner's name and a reasonable attempt will be made to notify the Owner of the change and a reasonable attempt will be made to notify the Owner of the change. The Owner will be responsible for the cost of the supply of electricity from the date of the change. The Owner is responsible for providing PowerStream with current and comprehensive contact and mailing information.

2.2 Disconnection

2.2.1 Power Stream Initiated

PowerStream reserves the right to disconnect the supply of electrical energy for causes not limited to:

- Contravention of the laws of Canada or the Province of Ontario, such as diversion of electricity, including the OESC;
- A materially adverse effect on the reliability and safety of the Distribution System;
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the Distribution System;
- A material decrease in the efficiency of the PowerStream's Distribution System;
- A materially adverse effect on the quality of distribution services received by an existing connection;
- Discriminatory access to distribution services;
- Inability of PowerStream to perform planned inspections and maintenance;
- Failure of the Customer or Customer's authorized representative to comply with a directive of PowerStream that PowerStream makes for purposes of meeting its license obligations;
- Failure of the Customer to enter into an OTC required by this COS;
- Overdue amounts payable to PowerStream for the distribution or "retailing" of electricity, or for non-payment of a security deposit;

- Electrical disturbance propagation caused by Customer equipment that is not corrected in a timely fashion
- By order of the ESA
- By order of the Independent Electricity System Operator (IESO)
- By order of another authority with jurisdictional power;
  - Any other conditions identified in this COS

PowerStream may disconnect the supply of electricity to a Customer without notice in accordance with a court order or as provided for under the *Law Enforcement and Forfeited Property Management Statute Law Amendment Act, 2005 (Bill 128)* , or for emergency, safety or system reliability reasons.

PowerStream shall not be liable for any damage to the Customer's premises resulting from such discontinuance of service.

2.2.1.1 Non-Payment of Overdue Amounts

Once bills are issued, there are normally sixteen (16) calendar days until the due date. Immediately following the due date, steps shall be taken to collect the full amount of the bill. Three (3) calendar days thereafter, the late payment penalty begins. Ten (10) calendar days after the penalty begins, a reminder notice is sent by regular mail. If the bill is still unpaid ten (10) calendar days after a disconnection notice is hand delivered to the Customer and the service may be disconnected any time thereafter and not restored until the amount due is paid in full by cash, certified cheque or money order, including the costs of reconnection. Such discontinuance of service does not relieve the Customer of the requirement to pay for arrears or minimum bills for the balance of the term of the contract, nor shall PowerStream be liable for any damage to the Customer's premises resulting from such discontinuance of service. Disconnection notices if given by registered mail shall be deemed to be received on the third business day after mailing.

Where the reason for the disconnection has been remedied to PowerStream's satisfaction, PowerStream shall reconnect a Customer. A reconnection charge shall apply where the service has been disconnected due to non-payment. All costs associated with the disconnection and reconnection shall be paid for by the Customer prior to reconnection of the service.

A standard notice advising Customers that their power has been disconnected is left behind with the disconnection notice in order to warn Customers of any potential fire and/or safety hazards.

The Customer or responsible designate must attend at the premises when distribution services are restored.

Under the following circumstances, PowerStream requires that the Customer obtain the approval of the ESA prior to PowerStream reconnecting the service:

- where PowerStream has reason to believe that the wiring may have been altered or damaged;
- where the service was disconnected for minimum period of six (6) months
- where the service was disconnected for modification of Customer wiring
- where the service was disconnected as a result of an adverse effect on the reliability and safety of the Distribution System
- where it is a requirement of the ESA

2.2.1.2 Unauthorized Energy Use

Unauthorized use of energy is a criminal offence. PowerStream reserves the right to disconnect the service for causes not limited to suspected "energy diversion", fraud or abuse on the part of the Customer. Such service may not be reconnected until the condition is rectified and full payment to PowerStream is made including but not limited to all costs incurred by PowerStream arising from unauthorized energy use, including inspections, repair costs, and the cost of disconnection and reconnection. This may also include the application of an approved miscellaneous charge.

2.2.4 Customer Initiated

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2.2.4.1 Maintenance Purposes

Upon receipt of a Customer's written request, PowerStream Customer Service will arrange for isolation and re-energization (disconnection and reconnection) for the purpose of performing work on or near electrical apparatus. This service, conducted during normal business hours, shall be available free of charge once per annum, per Customer.

2.2.4.2 Termination or Disconnection of Supply

Upon receipt of an Owner's written request for disconnection or "termination" of supply, PowerStream Customer Service will arrange for the disconnection and/or removal of PowerStream's connection assets.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guarantee of Supply

PowerStream will use "good utility practice" to provide a regular and reliable supply of electricity but does not guarantee this supply and shall not be liable for damages or production losses to the Customer for any loss of supply.

Customers requiring a higher degree of reliability than that of normal supply are responsible to provide their own back-up or standby facilities. Customers may require special protective equipment at their premises to minimize the effect of power interruptions.

Customers requiring a three-phase supply shall install protection apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributor's supply.

During an Emergency, PowerStream may interrupt supply to a Customer in response to a shortage of supply, or to conduct repairs on the Distribution System or Customer-owned equipment. PowerStream shall have rights of access to a property in accordance with the *Electricity Act, 1998, Section 40*.

To assist with Distribution System outages or Emergency response, PowerStream may require a Customer to provide PowerStream with Emergency access to Customer-owned distribution equipment that normally is operated by PowerStream or PowerStream owned equipment on Customer's property. Access to operable equipment shall not be reasonably withheld by the Customer.

To protect the three phase pad-mount transformers and to reduce the power outages due to the transformers failures, it is recommended that the delta-connected load be limited to 50% of connected load to the secondary side of the three phase pad-mount transformers.

2.3.2 Power Quality

2.3.2.1 Power Quality Testing

In response to a Customer power quality concern, where the utilization of electric power adversely affects the performance of electrical equipment, PowerStream will perform investigative analysis to attempt to identify the underlying cause. This may include review of relevant power interruption data, trend analysis, and/or use of diagnostic measurement tools.

Where the power quality concern results from a system delivery issue and where industry standards are not met, PowerStream will recommend and/or take appropriate mitigation measures. PowerStream will take appropriate actions to control power disturbances found to be detrimental to the Customers. If PowerStream is unable to correct the problem without adversely affecting other PowerStream Customers, then it is not obligated to make the corrections. PowerStream will use appropriate industry standards, such as International Electro-technical Commission (IEC) or Institute of Electrical and Electronic Engineers (IEEE) and good utility practice as a guideline. If the problem lies on the Customer side of the system, PowerStream may seek reimbursement from the Customer for the costs incurred in its investigation.

2.3.2.2 Power Factor

Customers connected to the PowerStream Distribution System shall operate at a "power factor" within the range of 0.9 lagging to 0.9 leading as measured at the meter point.

If Customers operate outside the specified power factor range, Customers are subject to a penalty adjustment on their electric bill.

2.3.2.3 Prevention of Voltage Distortion on Distribution System by the Customer

Customers having non-linear load shall not be connected to PowerStream's distribution system unless power quality is maintained by implementing proper corrective measures such as installing proper filters, and/or grounding. Further, to ensure the distribution system is not adversely affected, power electronics equipment installed must comply with IEEE Standard 519-1992. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

2.3.2.4 Obligation to Help in the Investigation

If PowerStream determines the Customer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on PowerStream's Distribution System, the Customer is obligated to help PowerStream by providing PowerStream with required equipment information, relevant data and necessary access for monitoring the equipment.

2.3.2.5 Timely Correction of Deficiencies

If an undesirable system disturbance is being caused by a Customer's equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken by the Customer at the Customer's cost. If the Customer does not take such action within a reasonable time, PowerStream may disconnect the supply of power to the Customer.

2.3.2.6 Notification For Interruptions

Although it is PowerStream's standard practice to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customer's supply to allow work on the electrical system. PowerStream will make reasonable efforts to provide Customers with reasonable notice of planned power interruptions. Notice may not be given where work is of an emergency nature involving the possibility of injury to Customers or damage to property or equipment.

However, during an Emergency, PowerStream may interrupt supply to a Customer, without notice, in response to a shortage of supply or to effect repairs on PowerStream's distribution system.

2.3.2.7 Notification To Consumers Using Life Support

"Consumers" who require an uninterrupted source of power for life support equipment must provide their own equipment for these purposes.

PowerStream shall not be liable in any manner to the Consumer for an interruption of power to a Consumer on life support.

2.3.2.8 Emergency Interruptions For Safety

PowerStream will attempt to notify Customers prior to interrupting the supply to any service. Service may be interrupted without notice, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to PowerStream or the public.

2.3.2.9 Emergency Service (Trouble Calls)

PowerStream shall exercise reasonable diligence and care to deliver a reliable supply of electrical energy to the Customer. When power is interrupted, the Customer should first ensure that the interruption is not due to the operation or failure of Customer-owned equipment within the Customer's premises. If there is a partial power condition on a three-phase service, the Customer should obtain the services of an electrical Contractor to conduct necessary repairs. Upon examination, should it appear that PowerStream's main source of supply has failed; the Customer should report these conditions immediately to PowerStream via telephone as per Section 1.5 of this COS.

PowerStream operates twenty-four (24) hours per day to provide Emergency service to Customers. PowerStream shall initiate restoration efforts as rapidly as practical.

2.3.2.10 Outage Reporting

The Power Outage Communication System (POCS) at 1-877-777-3810 is designed to handle an avalanche of incoming calls and is an essential tool in communicating situation updates and estimated restoration times to PowerStream Customers. For the most part, Customers calling into the POCS hang up after hearing recorded restoration information. Callers with outage information or who require more details are queued to speak with a System Controller or Customer Service Representative.

The POCS is also linked to the PowerStream website, giving site visitors access to real-time information about affected outage areas and estimated restoration times.

Depending on the outage, duration and the number of Customers affected, PowerStream may issue a news release to advise the general public of the outage.

2.3.3. Electrical Disturbances

PowerStream shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in Section 1.9 of this COS. Voltage fluctuations and other disturbances can cause flickering of lights and other serious difficulties for Customers connected to PowerStream's Distribution System. Customers must ensure that their equipment does not cause disturbances such as harmonics and spikes that might interfere with the operation of adjacent Customer equipment. Equipment that may cause disturbances includes large motors, welders, variable speed drives, etc. In planning the installation of such equipment, the Customer must consult with PowerStream.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms. PowerStream will assist in attempting to resolve any such difficulties at the Customer's expense.

Customers who may require an uninterrupted source of power supply or a supply completely free from fluctuation and disturbance must provide their own power conditioning equipment for these purposes.

2.3.4 Standard Voltage Offerings

2.3.4.1 Primary Supply Voltage

The primary distribution voltage to be used will be determined by PowerStream Depending on the locations in PowerStream's service territory the primary supply of voltage offering will be:

- 44 kilovolts (kV), delta, three wire; or
- 27.6/16 kV, grounded wye, three phase, four wire; or
- 13.8/8.0 kV, grounded wye, three phase, four wire; or
- 8.3/4.8 kV, grounded wye, three phase, four wire

Where multiple primary supply voltages exist, or where larger capacity loads are supplied, PowerStream will determine the voltage via consultation with the Customer or his representative.

2.3.4.2 Secondary Supply Voltages

Depending on what voltage of plant lies along PowerStream's distribution system, the secondary voltage shall be:

- 120/240 V, single phase, three wire,
- 120/208 V three phase, four wire, or
- 347/600 V, three phase, four wire.

The limit of supply capacity for any Customer is governed by the Nominal Operating Voltages, identified in sub-section 1.1.1 - Distribution Overview.

General guidelines for supply of loads from overhead street circuits are as follows:

- At 120/240 V, single phase up to 50 kVA demand load (200A)
- At 120/208 V, three phase, four wire up to 75 kVA demand load (200A)
- At 347/600 V, three phase, four wire up to 150 kVA demand load (200A)

General guidelines for supply where street circuits are buried are as follows:

- At 120/240 V, single phase up to 100 kVA demand load
- At 120/208 V, three phase, four wire up to 500 kVA demand load
- At 347/600 V, three phase, four wire up to 3,000 kVA demand load
- At 2400/4160 V, three-phase, four wire, @ 5000 kVA demand load

Where street circuits are buried, the Nominal Supply Voltage and limits will be determined upon application to PowerStream:

- When the Customer requires voltages other than at the available Nominal Supply Voltage shown above, or demands by a single occupant exceed 5000 kVA, Customers shall provide their own transformation as approved by PowerStream.
- At 27.6 kV, Customers with demand in excess of 15,000 kVA must make special arrangements with PowerStream for the supply of electricity.
- A 44 kV, Customers with demand in excess of 24,000 kVA must make special arrangements with PowerStream for the supply of electricity.
- Determination of load or thermal demand for the purposes of sizing PowerStream owned equipment or system shall be the responsibility of PowerStream.

2.3.4.3 Higher Reliability Supply Offerings

In most areas throughout its service territory, PowerStream offers its commercial/industrial customers the opportunity to choose a higher reliability service offering.

1. **Standard Service** – comprises one high voltage feeder with a single step down transformer.

2. **Silver Service** – comprises two high voltage feeders with automated switching on loss of one feeder with single step down transformer and continuous monitoring from PowerStream's Control Centre.

3. **Gold Service** - comprises two high voltage feeders with automated switching on loss of one feeder with two step down transformers and continuous monitoring from PowerStream's Control Centre.

The silver and gold higher reliability service offerings come with annual testing and maintenance programs as well as tailored reports on any power disturbances on the customer's service. Visit PowerStream's website for more information about these customer options.

2.3.5 Voltage Guidelines

PowerStream maintains service voltage at the Customer's service entrance within the guidelines of C.S.A. Standard CAN3-C235-83 (or latest edition), which allows variations from nominal voltage of, 5% for "Normal Operating Conditions", 8% for "Extreme Operating Conditions".

Nominal System Voltages	Voltage Variation Limited Application at Service Entrances			
	Extreme Operating Conditions			
		Normal Operating Conditions		
Single-Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
600	530	550	625	635
Three-Phase 4-Conductor				
120/208Y	110/190	112/194	125/216	127/220

347/600Y	306/530	318/550	360/625	367/635
Three-Phase 3-Conductor				
240	212	220	250	254
600	530	550	625	635
Taken from C.S.A. Standard CAN3-C235-87				

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action should be taken on a planned and programmed basis, but not necessarily on an emergency basis. Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action should be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved the extent to which limits are exceeded with respect to voltage levels and duration, etc.

PowerStream shall use good utility practice in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low or high voltage supply from the "transmitter". See Section 1.9 of this COS

2.3.6 Back-Up Generators

Customers with portable or permanently connected generation capability ("back-up generator") used for emergency back up shall comply with all applicable criteria of the latest edition of the OESC. In particular, the Customer shall ensure that the Customer's emergency generation does not parallel with PowerStream's system without a proper interface protection and does not adversely affect PowerStream's Distribution System.

Customers with permanently connected emergency generation equipment shall notify PowerStream regarding the presence of such equipment.

If a Customer intends to use embedded generation for load displacement please refer to Section 3.5.

2.3.7 Metering

2.3.7.1 General

PowerStream will normally meter the Customer's load at the utilization voltage. Except for secondary supply from the street, secondary metering equipment will be located as close as is practically possible to the supply transformer regardless of ownership of the supply transformer. Consult with PowerStream's New Services Department before secondary metering location is determined. Approved meter bases, enclosures and characteristics for the various types of metering installations can be found in the PowerStream's Metering Standards.

For settlement and billing purposes, PowerStream will supply, arrange installation, own, and maintain all meters, instrument transformers, ancillary devices, and secondary wiring required for revenue metering. Metered Market Participants in IESO administered wholesale market must meet or exceed all IESO metering requirements. The Customer agrees to provide PowerStream with remote access to the metering point, at the Customer's cost, for the purpose of maintenance and data collection.

Each Customer will normally be restricted to one metering point.

Metering and Service Standards are available on the PowerStream website.

2.3.7.2 Location of Metering

The mutually agreed upon location for PowerStream metering shall provide direct access for PowerStream staff and shall be subject to satisfactory environmental conditions. "Meter installations" shall conform to PowerStream's Metering Standards.

Where PowerStream deems its meters to be in a hazardous location, a meter cabinet or protective housing will be required. Where sprinkler equipment is in the vicinity of meter equipment, drip shields will be installed over all meters and related equipment.

Clear unobstructed access must be maintained to and in front of the meter location.

Any compartments, cabinets, boxes, sockets, or other workspace provided for the installation of PowerStream's metering equipment shall be for the exclusive use of PowerStream.

2.3.7.3 Types of Metering

Unless otherwise noted in Section 3 – Customer Class Specific, below are the standard metering requirements.

2.3.7.3.1 Single Phase – Secondary Metered

Single Phase Customers with services up to and including 200 A shall have 1.5 element, 4 jaw socket meters installed by PowerStream on the Customers PowerStream approved meterbase.

Where appropriate in a 400 Amp 120/240 volt single phase installation, a self contained 400 amp meter base complete with a current transformer shall be supplied and installed by the Customer. See PowerStream Metering Standards for approved meter base types.

Single Phase Customers with services of over 800 A shall submit drawings to PowerStream for approval prior to construction. Approved meterbase types and configurations are found in the PowerStream's Metering Standards.

2.3.7.3.2 Three Phase – Secondary Metered

All proposed three phase secondary metered services are required to be submitted to PowerStream for approval prior to construction. Three phase services up to and including 200 A will be metered by self contained socket meters on Customer owned PowerStream approved meterbases. Services over 200 A shall be metered by transformer type metering.

Approved meterbase, cabinet and switchgear specifications and configurations are found in the PowerStream's Metering Standards.

2.3.7.3.3 Totalized Metering

When a Customer requests totalizing in order to consolidate two or more Delivery Points at separate locations on one property, the following conditions shall apply:

(i) The Customer must own the distribution facilities, including transformers beyond the metering point. The effective metering point is defined as the location where the metering is installed.

(ii) Totalizing will be accomplished by either primary or secondary metering, through the use of remote interrogation metering, or other similar units. The Customer shall be required to pay the incremental costs of providing totalized metering.

(iii) The total capacity required will be less than the Delivery Point capacity.

2.3.7.3.4 Central Metering

PowerStream may, at its discretion, require that a Customer with two or more buildings at one location, be metered by means of a central metering installation. The Customer shall be required to pay PowerStream for the labour and material charges.

2.3.7.3.5 Multi-Unit Residential Suite Buildings

PowerStream does not offer bulk metering of multi unit buildings. All units within a multi-unit building will be 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.

2.3.7.3.6 Main Switch & Meter Installation for Industrial/Commercial Buildings

The metering provision and arrangement for service mains in excess of 200 amperes shall be submitted to PowerStream for approval before the building construction begins.

Any Customer's main switch immediately preceding the meter shall be installed as per OESC standards and shall permit the sealing and padlocking of: (a) the handle in the OPEN position; and (b) the cover or door in the closed position.

The owner is required to supply and install PowerStream approved meter bases or load centres for PowerStream's self-contained socket meters. For all meter base configurations, see PowerStream's Metering Standards. All plans for load centers shall be submitted to PowerStream for approval prior to material being ordered for a service.

For industrial/commercial services in excess of 200 A, the Owner is required to supply and install a meter cabinet to contain PowerStream's metering equipment, see PowerStream Metering Standards for meter cabinet size.

All services in excess of 800 A will be of the switchgear type. See the PowerStream Metering Standards for cabinet size.

2.3.7.3.7 Smart Meters

PowerStream will install Multi Unit Metering Systems (or Sub Metering Systems) as per the Ministry of Energy directives to the OEB.

2.3.7.3.8 Service Markings

The Customer shall permanently and legibly identify each metered service with respect to its specific address, including unit or apartment number. The identification shall be applied to all service switches, circuit breakers, meter cabinets, and meter mounting devices as well as those that are not immediately adjacent to the switch or breaker.

All new services in a multiple unit building are required to have unit numbers clearly identified on the tenant entry doors matched directly to each service supply switch or breaker.

2.3.7.3.9 Special Enclosures

Specially constructed meter entrance enclosures will be permitted for outdoor use upon written application for use to PowerStream and approval by PowerStream.

2.3.7.3.10 Meter Loops

Meter loops for Industrial/Commercial services shall be provided as per PowerStream Metering Standards.

Line and load entry points shall be restricted to opposite ends and on the lower half of the meter cabinet. These entry points must be correctly marked LINE and LOAD.

Mineral insulated, solid or hard drawn wire conductors are not acceptable for meter loops.

The neutral conductor will be terminated on an insulated block at the bottom center of the meter cabinet. This neutral block shall be set back one to two inches from the front edge of the cabinet if the neutral is not required past the metering point. The neutral block shall have provisions for a #10 wire to be used for a metering neutral connection. If the neutral is needed past the metering point the conductors will be run along the bottom of the cabinet and not be looped as the other phases. PowerStream will supply a split bolt and connect a #10 wire to the neutral inside the meter cabinet if necessary.

2.3.7.3.11 Barriers in Electrical Enclosures

Barriers are required in each section of switchgear or service entrance equipment between metered and unmetered conductors and/or between sections reserved for PowerStream use and sections for Customer use.

2.3.7.3.12 Doors for Electrical Enclosures

Side hinged doors shall be installed on all live electrical equipment where PowerStream personnel may be required to work (e.g.) line splitters, un-metered sections of switchgear, breakers, switches, metering compartments, meter cabinets and enclosures.

These hinged doors shall have provision for sealing and padlocking. Where bolts are used, they shall be of the captive knurled type. All outer-hinged doors shall open no less than 135 degrees. All inner-hinged doors shall open to a full 90 degrees.

2.3.7.3.13 Auxiliary Connections

All connections to circuits such as fire alarms, exit lights and Customer instrumentation shall be made to the load side of PowerStream's metering.

No Customer equipment shall be connected to any part of PowerStream's metering circuit.

Fire sprinkler system services shall be installed as per the OESC.

2.3.7.3.14 Working Space for Metering Equipment

A clear minimum working space of one metre shall be maintained in front of all equipment and from all side panels. This space shall have a minimum of 2.1 metres of unobstructed headroom. No meter installation will protrude into a doorway, be located behind sprinkler systems or be built into a closet with less than 1 meter clearance in front of the meter. All machinery located within 3 meters of the meter equipment shall have guards installed on the machinery to prevent injury to PowerStream personnel when servicing meter equipment. All self-contained meters will have a minimum of 450mm of clearance from the side of the meterbase to an inside corner of a wall or equipment that protrudes more than 300mm from the wall.

Where a hinged door in an open position would block an exit route, a further 600mm of clearance from the edge of the open door shall be provided.

2.3.7.4 Meter Cabinet and Instrument Transformer Enclosures

All instrument transformer enclosures must be approved by PowerStream prior to construction.

When instrument transformers (current transformers and voltage transformers) are incorporated into low voltage switchgear, the Customer will supply a separate meter cabinet. This meter cabinet will be located to the satisfaction of PowerStream and as close as possible to the instrument transformer compartment(s). The meter cabinet along with the instrument transformer enclosure must be visible from the main switch. The meter cabinet must also be properly grounded with a minimum #6 copper grounding conductor not connected to the metering circuit.

The Customer's electrical contractor is required to install PowerStream's current transformers in the Customer's low voltage switchboard. Arrangements must be made with the PowerStream Meter department to have the instrument transformers delivered to the site prior to meter installation.

The conduit for the PowerStream metering wires must run continuous from the Customer owned Instrument Transformer compartment to the metering cabinet. The conduit will enter the utility compartment in an unobstructed location. No more than one sharp 90 degree conduit bend (LB) may be used in a single conduit run. Any LB will be installed in an easily accessible and unobstructed location.

PowerStream will issue specific metering requirements where two or more circuits are totalized, or where remote totalizing is involved, or where instrument transformers are incorporated in high voltage switchgear (greater than 750 V).

2.3.7.5 Interval Metering

"Interval meters" will be installed for all new or upgraded services where the peak demand is forecast to be 200 kW or greater, pending any Legislative Changes, or for any Customer requesting the installation of an interval meter.

2.3.7.5.1 Interval Meter Telephone Line

Prior to the installation of an interval meter the Customer must provide a telephone line or extension to the meter cabinet or meter base. The Customer will arrange for the installation of a telephone line in one half inch conduit, terminated at the metering point for the exclusive use of PowerStream to retrieve interval meter data. The Customer will be responsible for the installation, maintenance and ongoing monthly costs of operating the phone line. The phone line will be direct dialling voice quality, active 24 hours per day, and energized prior to meter installation. Failed Customer communication lines must be repaired within 48 hours of notification from PowerStream. If repairs are not completed within this time frame, PowerStream will have to manually collect the interval meter reads done every second day after the notification. The Customer will be invoiced for all costs associated with the manual meter readings.

2.3.7.5.2 Customer Request for Interval Metering

Other Customers that request interval metering shall compensate PowerStream for all incremental costs associated with that meter, including:

- the capital cost of the interval meter,
- installation costs associated with the interval meter,
- ongoing maintenance (including an allowance for meter failure),
- verification and re-verification of the meter,
- installation and ongoing provision of a communication line or communication link with the Customer's meter.

2.3.7.5.3 Customer Request for Interval Meter Data

The Customer has the following three options to obtain their interval meter data:

- Direct access – The Customer may elect to access the meter data directly using Customer-purchased software. PowerStream shall provide information required to access and use the meter data;
- Web access provided by PowerStream (when available) - Customers shall have access to their own interval meter data on the internet using their own account-specific password;
- Information provided by PowerStream – Customers may request interval data to be forwarded by PowerStream or its authorized representative.

2.3.7.5.4 Customer Request for Meter Pulse Output or Real-Time Meter Data

If the Customer requires metering pulses or real-time data, the Customer shall be responsible for installing and maintaining a telecommunications line at the Customers own expense.

When a Customer requires metering pulses or signals for load management purposes, two options exist.

- The Customer can supply and install their own instruments in a separate cabinet on the load side of PowerStream’s metering; or
- PowerStream will supply the pulses from PowerStream’s metering, provided the Standard Customer pays all costs to provide the pulses, and that the control for the pulses will be remote from the revenue metering cabinet (Customer will not have access to revenue metering cabinet).

2.3.7.6 Meter Reading, Inspection and Access to Meter Equipment

The Customer must provide or arrange free, safe and unobstructed access during regular business hours to any authorized representative of PowerStream for the purpose of meter reading, meter changing, or meter inspection. Where premises are closed during PowerStream's normal business hours, the Customer must, on reasonable notice, arrange such access at a mutually convenient time.

2.3.7.7 Final Meter Reading

When a service is no longer required, the Customer shall provide notice within three (3) business days of the date the service is to be discontinued so that PowerStream can obtain a final meter reading as close as possible to the "final reading date". The Customer shall provide access to PowerStream or its agents for this purpose. If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.8 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the federal *Electricity and Gas Inspection Act* and associated Regulations, under the jurisdiction of Measurement Canada. PowerStream's revenue meters are required to comply with all specifications established by the Regulations under the above Act.

In the event of incorrect electricity usage registration, PowerStream will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied based on the reading of any meter formerly or subsequently installed on the premises by PowerStream, with due regard being given to any change in the characteristics of the installation and/or the demand.

2.3.7.9 Meter Dispute Testing

Metering inaccuracy is an extremely rare occurrence. Most billing inquiries can be resolved between the Customer and PowerStream without resorting to the meter dispute test.

Either PowerStream or the Customer may request the service of Measurement Canada to resolve a dispute.

If the Customer initiates the dispute, and the meter is found to be accurate and Measurement Canada rules in favour of PowerStream, PowerStream shall charge the Customer an OEB-approved meter dispute fee.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. PowerStream will correct the bills for that period in accordance with the Regulations under the *Electricity and Gas Inspection Act*.

2.3.7.10 Electrical Room for Meter(s) or Metering Installation(s)

The Owner is required to visibly identify the electrical room from the outside... PowerStream will install a PowerStream METERS identification label on the electrical room door.

When two or more metered services are required, the owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the OESC. All such rooms shall conform to all existing building standards.

Access doors, panels, slabs and vents shall be kept free from obstructing objects for the purpose of installing, removing, maintaining, operating or changing transformers and associated equipment. The room shall not be used for storage.

All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code and shall be located indoors.

In order to allow for an increase in load, the owner shall provide spare wall space so that at least 30% of the Customers supplied through “meter sockets” can accommodate meter cabinets at a later date.

The electrical room shall be visibly identified from the outside.

The electrical room must be located to provide safe access from the outside so that it is readily accessible to PowerStream’s employees and agents at all hours to permit meter reading and to maintain electric supply.

Prior to energization, the owner will be required to obtain through PowerStream a wall key holder to be mounted outside the meter room door by PowerStream personnel as per the PowerStream Metering Standards. Arrangements for purchasing this holder and obtaining extra keys shall be coordinated with PowerStream Meter Department Supervisor. The owner will then supply PowerStream with a key to the electrical room to be kept inside the holder for PowerStream's exclusive use.

All new electrical rooms are required to have an up to date building unit layout plan for the building mounted on an inside wall, showing the unit layouts, contact names and phone numbers for property managers and / or maintenance personnel.

The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space.

The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault circuit shall be supplied from a panel located and clearly identified in the electrical room.

Outside doors providing access to electrical rooms must have at least 150-mm clearance between final grade and the bottom of the door. Electrical rooms 'on' or 'below' grade must have a drain including a P-trap complete with a non-mechanical priming device and a backwater valve connected to the sanitary sewer. The electrical room floor must slope 6-mm/300 mm or 2% towards the drain.

Finally, all new meter rooms shall have provisions for a voice quality, analogue telephone line with at least one spare pair of wires for PowerStream's exclusive use for meter interrogation purposes. It shall be the building owner's responsibility to bear the installation, maintenance and monthly service charges for this line.

2.3.7.11 Electrical Service Upgrades for Existing Tenants

For service upgrades to existing tenant electrical services, PowerStream requires that all meter bases be identified with the correct unit number(s). It is the building owner's responsibility to ensure that the correct meter bases are allocated to the correct unit and permanently marked accordingly.

2.4 Tariffs and Charges

Tariffs and charges under this section pertain to OEB approved rates and charges. These tariffs relate to the supply of energy and related distribution services to Customers in the service territory.

2.4.1 Service Connection

Charges for distribution services are determined as set out in the Schedule of Rates available from PowerStream. Notice of rate revisions shall be published in local newspapers, billing inserts, newsletters and/or the PowerStream website.

These are OEB approved charges and are subdivided into Customer Administration, Non-Payment of Account, and Special Charges for Access to Power Poles and Special Allowances.

2.4.1.1 Customers Switching to Retailers

There are no physical service connection differences or service connection requirements between Standard Service Supply (SSS) Customers and third party Retailers' Customers. For both Customer groups, energy supplies are delivered through the local Distributor with the same distribution requirements.

2.4.2 Energy Supply

2.4.2.1 Standard Service Supply (SSS)

All existing PowerStream Customers are SSS Customers until PowerStream is informed of their switch to a competitive electricity supplier. The Service Transfer Request (STR) must be made by the Customer or the Customer's authorized Retailer as per the RSC.

2.4.2.2 Retailer Supply

Customers transferring from SSS to a Retailer shall comply with the STR requirements as outlined in sections 10.5 through 10.5.6 of the RSC. All requests shall be submitted as electronic files and transmitted through the Electronic Business Transaction (EBT) system. STR's shall contain information as set out in section 10.3 of the RSC. If the information is incomplete PowerStream shall reject the STR and notify the requesting party that the request cannot be processed as per the RSC, Section 10.4.

2.4.2.3 Wheeling of Energy

All Customers considering delivery of electricity through the PowerStream Distribution System are required to contact PowerStream for technical requirements and applicable tariffs.

2.4.3 Deposits

Refer to the PowerStream Consumer Security Deposit Policy, Appendix E of this COS.

2.4.4 Billing

PowerStream has established a billing method and billing cycles to provide Customers with services through SSS or through a third party Retailer, as per the rules and regulations set out in the RSC.

2.4.4.1 Billing Cycle

PowerStream may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis.

Bills for the use of electrical energy and services may be based on either a metered rate or a flat rate, as determined by PowerStream. Customers are divided into billing cycles and each cycle is read and billed at approximately the same time each billing period based on a previously determined schedule.

PowerStream reserves the right to adjust billing cycles and frequencies as required.

2.4.4.2 Settlement Costs

The competitive and non-competitive settlement costs are calculated according to the RSC Sections 3 and 4.

The settlement options, as outlined in Section 7 of the RSC are:

- Retailer-consolidated billing;
- Distributor-consolidated billing;
- Split billing (when determined by the OEB); and
- SSS billing.

2.4.4.3 Disputes

The Customer may dispute charges shown on the Customer's bill, or other matters, by contacting and advising PowerStream of the reason for the dispute. PowerStream shall promptly investigate all disputes and advise the Customer of the results. For formal disputes, the dispute process outlined in Section 1.8 of this COS shall be followed.

2.4.4.4 Transformer Ownership Credit

Customers who own their own primary transformation facilities are entitled to an OEB approved transformation allowance credit and are on file with PowerStream. PowerStream has the authority to apply to the OEB for site specific loss rates for those secondary-metered Customers who own their own transformation equipment or who have additional stages of transformation prior to their loads being metered. Any revisions shall be published in accordance with the DSC. Customers must submit transformer losses for review and approval by PowerStream prior to energization.

2.4.5 Payments

2.4.5.1 Payments and Overdue Account Interest Charges

PowerStream has established payment methods for the Customer regarding distribution services, other non-competitive charges, and energy supply through SSS, or through a third party Retailer as per the rules and regulations set out in the RSC.

2.4.5.2 Payment Options

Customers may pay their bill by using any of the following methods: cheque, certified cheque or money order mailed to the address indicated on the bill; cash, cheque, debit card, certified cheque or money order at PowerStream's cashier locations; or by bill payment services as offered through most Canadian financial institutions. All payments are to be in Canadian dollars.

Payments associated with the reconnection of a service due to non-payment of an account shall be by cash, money order or certified cheque at one of our cashier locations only. Payments associated with a diversion of power shall only be by certified cheque or money order.

PowerStream also offers two pre-authorized payment plans. The Pre-Authorized Payment Plan (PAP) allows Customers to pay the amount due on the due date indicated on the bill. The Equal Payment Plan (EPP) allows Customers to pay an equal amount on a predetermined date each month over two seasonal six month periods, adjusted by consumption changes, if necessary and any leftover balances to roll forward into the next period. All EPP accounts will be reviewed periodically to ensure the monthly payment amount accurately reflects billed amounts. PowerStream reserves the right to adjust the monthly EPP amount upon written notification.

2.4.5.3 Late Payment Charges

Bills are due when rendered for services provided to the Customer. Bills are payable in full by the due date, which shall be a minimum of sixteen (16) calendar days from the date of billing. A Customer can pay without the application of a late payment charge up to the due date. Late payment interest charges shall apply at an OEB approved rate of 1.5% per month, compounded to 19.56% per annum, on past due balances. Where a partial payment has been made by the Customer on or before the due date, the interest charge shall apply only to any outstanding balance at the due date.

Outstanding bills are subject to the collection process and may ultimately lead to the service being disconnected or a load limiter being installed thereby restricting the supply of electrical power. Service shall not be restored until satisfactory payment has been made. Services that have been restricted with a load limiter shall only be restored during normal working hours. Discontinuance of service does not relieve the Customer of the liability for arrears.

Management may exercise judgment with respect to risk of non-payment and individual Customer circumstances.

2.5 Customer Information

PowerStream will not disclose information regarding a Customer, Retailer, Wholesale Market Participant or Generator to any other party without the written consent of the Consumer, Retailer, Wholesale Market Participant, or Generator, except where such information is required to be disclosed:

- To comply with any legislative or regulatory requirements;
- For billing, settlement or market operations purposes;
- For law enforcement purposes;
- To a debt collection agency for the processing of past due accounts of the Consumer, Retailer, Wholesale Market Participant or Generator.

2.5.1 Disclosure of Historical Usage to a Third Party

Historical usage information on a particular Customer may be disclosed to a third party with the written consent of the Customer. The information to be provided will be what is readily available to a maximum of twenty-four (24) months. PowerStream may charge a fee for this service.

2.5.1.1 Aggregated Information

PowerStream will disclose information regarding Consumers, Retailers, Wholesale Market Participants or Generators, where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. Fees for aggregated information will not be assessed to another Distributor, transmitter, the IESO, the Ontario Power Authority (OPA) and the OEB. However, subject to OEB approval, PowerStream reserves the right to assess fees to other parties.

2.5.1.2 List of Retailers

At the request of a Customer, PowerStream shall provide a list of Retailers that have "Service Agreements" in effect within its distribution service area.

2.5.1.3 Request Response or Referral

Upon receiving an inquiry from a Customer connected to its distribution system, PowerStream will either respond to the inquiry if it deals with its own distribution services or provide the Customer with contact information for the entity responsible for the item of inquiry, in accordance with Chapter **7** of the RSC.

- End of Section -

SECTION 3 – CUSTOMER CLASS SPECIFIC

3.0 General

PowerStream shall recover costs associated with the installation of "Connection Assets", by customer class, via a Basic Connection Charge and a Variable Connection Charge, as applicable.

Class 1: Residential – Single Service

Class 2: General Service <50 kilowatts (kW)

Class 3: General Service 50 kW to 4999 kW

Class 4: General Service >= 5,000 kW

Note: Basic Connection Charges are reviewed annually and are calculated based on the average costs to provide the Standard Allowance and the Basic Connection for each customer class. Standard fees are determined using historical data from previous year(s) for all completed projects in each customer class. Please refer to the PowerStream website for the appropriate schedule of rates and charges.

3.1 Service Information – All Customer Classes

The Customer shall supply the following to PowerStream well in advance of installation commencement:

- Required in-service date;
- Proposed service entrance equipment's rated capacity (Amperes), voltage rating and metering requirements;
- Survey plan and site plan indicating the proposed location of the service entrance equipment with respect to public rights-of-way and lot lines; and
- Electrical, architectural and/or mechanical drawings as required by PowerStream.

Additional services charged to the Customer (as part of the Variable Connection Fee) are for redesign due to changes in the Customer's initial proposal, for utility inspections more than the standard allowance and for all civil inspections and / or scope and timing

PowerStream is responsible for the maintenance and repairs of its Connection Assets but not the transformer room(s) or any other civil structure that forms part or is part of the Customer's building.

When effecting changes the Customer shall maintain sufficient clearances between electrical equipment and Buildings and other permanent structures to meet the requirements of the OESC and the *Occupational Health & Safety Act* and Regulations.

For Metering requirements, refer to Section 2.3.7.1 of this COS.

If an Electrical Room is required, refer to Section 2.3.7.10 of this COS.

It is the responsibility of the owner or its contractor to obtain clearances for the locations of all utility services, such as electric, gas, telephone, water and cable TV, from all utility companies (including PowerStream) before digging.

The Customer shall construct or install all civil infrastructure (including but not limited to poles, underground conduits, cable chambers, cable pull rooms, transformer room/vault/pad) on private property that is deemed required by PowerStream as part of its Connection Assets. All civil infrastructures are to be in accordance with PowerStream's current standards, practices, specifications and this COS and are subject to PowerStream's inspection and acceptance.

Where the size of the Customer's electrical service warrants, the Customer will be required to provide facilities on its property and an easement as required, acceptable to PowerStream, to house the necessary transformer(s) and/or switching equipment. PowerStream will provide planning details upon application for service.

PowerStream will supply, install and maintain the electrical transformation equipment within the transformer vault or pad. PowerStream has the right to have this equipment connected to its Distribution System.

The Customer's cables shall be brought to a point determined by PowerStream for connection to PowerStream's supply.

PowerStream will undertake the necessary programs to maintain and enhance its distribution plant at its expense. In the event that services or facilities to a Customer need to be restored as a result of construction or maintenance activities by PowerStream, they will be restored to an equivalent condition.

In addition PowerStream will carry out the necessary construction and electrical work to maintain existing supplies by providing standard overhead or underground supply services to Customers affected by PowerStream's construction activities. If a Customer requests special construction beyond the normal PowerStream standard installation in accordance with the program, the Customer shall pay the additional cost, including engineering and administration fees.

The typical demarcation point for services over 750 V is at the point of connection to the distribution system.

Secondary services under 750 V the typical demarcation point is at the secondary terminals of the supply transformer.

3.2 Class 1 - Residential Service

The Ontario Energy Board defines the "Residential Service" Customer classification as 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.

The Basic Connection Charge is recovered through PowerStream's rates and covers the Standard Allowance for Basic Connection consistent with the defined ownership demarcation point. This point may differ from the operational demarcation point.

The Standard Allowance for Basic Connection is up to 30 meters of 200A, low-voltage overhead wire or equivalent credit for underground service, and also and transformation capacity or an equivalent credit for transformation equipment. The Standard Allowance does not include road crossings.

The Variable Connection Charge shall be calculated as the costs associated with the installation of connection assets above and beyond the Standard Allowance for Basic Connection. PowerStream may recover this variable connection fee, which shall be based on firm cost.

3.2.1 Overhead Services

- Ownership Demarcation Point is typically the top of the Customer's service mast unless otherwise noted in the design.

- For the Variable Connection Fee the Customer is charged the firm service agreement costs.

In addition to the requirements of the OESC, the following conditions shall apply:

- Clearance must be provided between utility conductors and finished grade of a least 6 metres (19 feet) over traveled portions of the road allowance and 4.5 metres (15 feet) over all other areas. A minimum horizontal clearance of 1.0 metres (39 inches) must be provided from utility conductors and any second storey windows.

- Although the OESC allows electrical conductors to be located at adequate height, PowerStream will not allow electrical conductors to be located above swimming pools.

  Where a new swimming pool is to be installed it will be necessary to relocate, at the property owner's expense, any electrical conductors located directly over the proposed pool location. Where overhead service conductors are in place over an existing swimming pool, PowerStream will provide up to 30 metres of overhead service conductors, at no charge, to allow rerouting of the service. The property owner will pay any other costs.

3.2.2 Underground Services

- Ownership Demarcation Point is the line side of the Customer's meter base for a typical installation / design.

- Customers requesting an underground service will be required to pay 100% of the connection costs for the underground service less a credit for the Standard Allowance.

- For the Variable Connection Fee the Customer is charged the firm costs for Connection Assets beyond the Standard Allowance, including road crossing.

The trench route must be approved by PowerStream and is to follow the route indicated on the underground drawing supplied by PowerStream. PowerStream must approve any deviation from this route. The Customer will be responsible for PowerStream's costs associated with re-design and inspection services due to changes or deviations initiated by the Customer or its agents.

It is the responsibility of the owner to contact PowerStream to inspect each trench prior to the installation of PowerStream's service cables.

3.3 General Service (< 50 kW, 50 – 4999 kW, => 5000 kW)

- The Ownership Demarcation Point, unless otherwise noted in the design, is:
  - Overhead service: the top of the service mast.
  - Underground service: the connection to PowerStream's distribution system.
- For the Variable Connection Fee, unless otherwise noted, the Customer is charged the firm service agreement costs
- Additional Services Charged to Customer (as part of the Variable Connection Fee), unless otherwise noted are for redesign due to changes in the Customer's proposal.
- The Service Disconnection Fee (initiated by Customer request), unless otherwise noted, are the actual costs associated with the disconnection.

3.3.1 Technical Information

Prior to the preparation of a design for a service, the Customer or its authorized representative will provide to PowerStream:

- the approximate date that the Customer requires the electrical service,
- one copy of all relevant project drawings (if required),
- proof of legal ownership, and
- the due date that PowerStream's civil construction drawings are required to co-ordinate with site construction.

All drawings must be submitted to PowerStream with adherence to PowerStream's Standards. Where the Customer requires an approved copy to be returned, two copies of all plans must be submitted.

- **Site & Grading Plans** - Indicate the lot number, plan numbers and when available, the street number. The site plan shall show the location of the Building on the property relative to the property lines, any driveways and parking areas and the distance to the nearest intersection. All elevations shall be shown for all structures and proposed installations.

- **Mechanical Servicing Plan -** Show the location on the property of all services proposed and/or existing such as water, gas, storm and sanitary sewers, telephone, etc.

- **Floor Plan -** Show the service location, other services locations, driveway, and parking and indicate the total gross floor area of the building.

- **Duct Bank Location -** Show the preferred routing of the underground duct bank on the property. This is subject to approval by PowerStream.

- **Transformer Location -** Indicate the preferred location on the property for the high voltage transformation. This is subject to approval by PowerStream. Transformation will be vault, pad, submersible type or pole mounted depending on the project load requirements.

- **Electrical Meter Room -** Indicate preferred location in the building of the meter room and the main switchboard.

- **Single Line Diagram -** Show the "main service" entrance switch capacity, the required supply voltage, and the number and capacity of all "sub-services" showing provision for metering facilities, as well as the connected load breakdown for lighting, heating, ventilation, air conditioning etcetera. Also, indicate the estimated initial kilowatt demand and ultimate maximum demands. Provide protection equipment information where coordination is required between PowerStream and Customer owned equipment. PowerStream will determine fusing later to coordinate with the transformer size selected.

- **Switchgear -** Submit three copies of any service entrance switchgear to be installed for PowerStream's approval, including interlocking arrangement if required.

- **Substation Information -** Where a Customer owned substation is to be provided, the owner will be required to provide the following in addition to the site information outlined above.

    - All details of the transformer, including kVA capacity, short-circuit rating, primary and secondary voltages, impedance and cooling details.
    - A site plan of the transformer station showing the equipment layout, proposed primary connections, grounding and fence details, where applicable.
    - A coordination study for protection review.

3.3.2 Technical Considerations

- **Short Circuit Ratings**

    - **44000 V Supply: -** The Customer's protective equipment shall have a three phase, short circuit rating of 1500 MVA symmetrical. The asymmetrical current is 32,000 A (1.6 factor used).

    - **16000/27600 V Supply**: - The Customer's protective equipment shall have a three phase, short circuit rating of 800 MVA symmetrical. The asymmetrical current is 26,000 A (1.6 factor used).

    - **8000/13800 V Supply**: - The Customer's protective equipment shall have a three phase, short circuit rating of 500 MVA symmetrical. The asymmetrical current is 37,000 A (1.6 factor used.)

    - **2400/4160 V Supply**: - The Customer's protective equipment shall have a three phase, short circuit rating of 250 MVA symmetrical or 40,000 A asymmetrical (1.6 factor used).

    - **600/347 V Supply**: - The Customer's protective equipment shall have a minimum short circuit rating of 50,000 A.

    - **208/120 V Supply**: - Available short circuit current may be obtained upon request to PowerStream.

- **Primary Fusing** - All equipment connected to the PowerStream Distribution System shall satisfy the short circuit ratings specified above. The Customer and/or its consultant shall specify the fuse link rating and demonstrate coordination with PowerStream's upstream protection including station breakers and/or distribution fuses where possible. The Customer shall submit a coordination study to PowerStream for verification to ensure coordination with upstream protection including station breakers and/or distribution fuses. The Customer shall maintain an adequate supply of spare fuses to ensure availability for replacement in the event of a fuse blowing.

- **Ground Fault Interrupting** - Where ground fault protection is required to comply with the OESC, the method and equipment used shall be compatible with PowerStream's practice of grounding transformer neutral terminals in vaults. Zero sequence sensing will normally apply. Where ground strap sensing is used, the ground sensing devices shall be set to operate at 600 A if transformer and switchboard buses are not bonded and 400 A if buses are bonded. Ground fault protection proposals for dual secondary supply arrangements shall be submitted to PowerStream for approval, before construction of the switchboard.

- **Lightning Arresters** - Customer installations that are directly supplied from PowerStream's primary underground system are not protected with lightning arresters. If the Customer wishes to install lightning arresters they shall be located on the load side of the first protective device. For Customer installations that are supplied from PowerStream's primary overhead system, PowerStream will install lightning arresters at the pole and the Customer may install lightning arresters in the switchgear on the load side of the incoming disconnect device. The mimic diagram shall indicate the presence of such devices in the switchgear.

- **Basic Impulse Level (B.I.L.)** - The Customer's apparatus shall have a minimum B.I.L. as per the OESC.

- **Unbalanced Loads** - On three-phase service, the unbalance due to single-phase loads shall not exceed 20% of the Customer's balanced phase loading expressed in kW.

3.3.3 Class 2 - General Service Less Than 50 kW

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

- For the Variable Connection Fee the Customer is charged the actual costs for connection, metering and system enhancement charges, if applicable.

- Additional services charged to the Customer (as part of Variable Connection Fee) are for redesign due to changes in Customer's initial proposal, utility inspections more than standard allowance and all civil inspections.

The Customer shall supply details respecting heating equipment, air-conditioners, motor starting current limitation and any appliances, which demand a high consumption of electrical energy to PowerStream well in advance of installation commencement:

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3.3.3.1 Temporary Services

A temporary service is a normally metered service provided for construction purposes or special events. Temporary services can be supplied overhead or underground. The Customer will be responsible for all associated costs for the installation and removal of equipment required for a temporary service to PowerStream's "point of supply". Temporary services may be provided for a period of no more than 12 months. Temporary services must be renewed thereafter if an extension is required and the equipment for such temporary service must be re-inspected at the end of the 12-month period.

Subject to the requirements of PowerStream, supply will be connected after receipt of a Connection Authorization from the ESA, a signed contract and a deposit from the Customer.

Where meter bases are required, they must be approved by PowerStream and shall be securely mounted on minimum 152 mm diameter poles (or alternative if approved by PowerStream) so that the midpoint of the meter is 1.73 m (± 100 mm) from finished grade.

In the case of temporary overhead services, the Customer shall leave 760 mm of cable at the masthead for connection purposes.

In the case of temporary underground services, the Customer's cable shall extend to PowerStream's point of supply.

3.3.4 Class 3 - General Service 50 kW - 4999 kW

This classification applies to a non residential account whose average monthly demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5000 kW. For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer.

The Customer shall supply the following to PowerStream well in advance of installation commencement:

- Proposed total load details in kVA and/or kW (winter and summer)
- Details respecting heating equipment, air-conditioners, motor starting current limitation and any appliances, which demand a high consumption of electrical energy
- For the Variable Connection Fee the Customer is charged the actual costs for connection assets and installation. For underground services this also includes connection to the secondary side of PowerStream's transformer. Includes road crossing if required.

3.3.5 Technical Considerations – > 1000 kW

Where a primary service is provided to a Customer-owned substation, the Customer shall install and maintain such equipment in accordance with all applicable laws, codes, regulations, and PowerStream's requirements for high voltage installations. Customer transformers must be approved by PowerStream. PowerStream will provide planning details upon "application for service"

Customer owned substations are a collection of transformers and switchgear located in a suitable room or enclosure owned and maintained by the Customer, and supplied at primary voltage, i.e. the Supply Voltage is greater than 750 V.

The Customer is required to bring out a neutral conductor for connection to the system neutral (except 44 kV systems). If not required for Customer's use, this neutral shall be terminated to the Customer's station ground system. PowerStream will provide Customer interface details and requirements for high voltage supplies.

Customer owned substations must be inspected by both the ESA and PowerStream. The owner will provide a pre-service inspection report to PowerStream. A contractor acceptable to PowerStream shall prepare the certified report.

To facilitate and encourage the maintenance of this equipment, PowerStream will provide one power interruption annually, at no charge, in lieu of or coincident to interruptions arranged for the installation, maintenance, and testing of vault fire alarm detectors. This no-charge service would be scheduled during PowerStream's normal business hours and are not necessarily guaranteed. PowerStream will charge Customers for power interruptions arranged at times other than as outlined above.

3.3.6 Class 4 - Large User – Equal to or Greater than 5,000 kW

The "large user" classification applies to a non residential account whose average monthly demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer.

- For the Variable Connection Fee the Customer is charged the actual costs for connection, metering and system enhancement changes, if applicable.

3.3.7 Technical Considerations

See Section 3.3.5

3.4 Unmetered Connections (Scattered Loads)

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is 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.

This section will include all terms and conditions applicable to unmetered connections such as but not limited to the following:

- Traffic signals
- Pedestrian crosswalk signals and beacons
- Bus shelters
- Telephone booths
- Signs <5kW
- Miscellaneous “unmetered loads” <5kW

Traffic signals and pedestrian crosswalk signals and beacons shall have a rate structure equal to General Service (< 50 kW) class Customers. Each traffic signal and pedestrian crosswalk and beacon location is reviewed individually and is connected to PowerStream’s low voltage distribution system. ESA Authorization to Connect is required prior to connecting the service.

The Ownership Demarcation point is as follows:

- For Overhead - the top of the Customer’s service standpipe/mast.
- For Underground – the line side of the fuse in the first hand-well, tap box, junction box (as applicable) beyond PowerStream’s plant.

Re-design and inspection services are at extra costs to the Customer. The Customer is responsible for maintaining and repairing its equipment and/or facilities.

3.4.1 Street Lighting

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

- Ownership demarcation point for street lighting varies with the type of services (underground or overhead), equipment, and municipal areas. Consult PowerStream to get the information on street lighting demarcation points.
- Decorative or tree lighting, if connected to the municipal or the Province of Ontario Street Lighting system, will be treated as a Street Lighting Class of service.

3.5 Embedded Generation Facilities

The Generator Classifications set forth in the Distribution System Code are outlined in the table below:

Generator Classification	Rating
Micro	≤ 10 kW, for customer's own use
Small	a) > 10kW but ≤ 500kW, connected on distribution system voltage < 15 kV
	b) > 10kW but ≤ 1 MW connected, on distribution system voltage ≥ 15kV
Mid-Sized	a) > 500kW but ≤ 10 MW, connected on distribution system voltage < 15 kV
	b) > 1 MW but ≤ 10 MW, connected on distribution system voltage ≥ 15kV
Large	> 10 MW

3.5.1 Connection Agreement

PowerStream shall enter into a Connection Agreement with all existing Customers who have an embedded "generation facility" connected to the PowerStream distribution system and also with all new Customers prior to connecting a new generation facility.

For micro, small, mid-sized, and large embedded generation facilities, the Connection Agreement shall be in the form set out on the PowerStream website

Where PowerStream does not have a Connection Agreement with an existing Customer that has a generation facility connected to the PowerStream distribution system, the Customer shall be deemed to have accepted and agreed to be bound by all of the

Connection Agreement Terms and Conditions set out on the PowerStream website and the terms of any operating schedule delivered to it from time to time by PowerStream.

3.5.2 Connection Process

PowerStream has created an "Embedded Generation Connection Overview" which contains the following information:

a) the process for having a generation facility connected to the PowerStream distribution system, including any form necessary for the application;

b) information regarding any approvals from the ESA, the IESO, OEB, OPA, or a transmitter that are required before PowerStream will connect a generation facility to its distribution system;

c) the technical requirements for being connected to the PowerStream distribution system including the metering requirements; and

d) the standard contractual terms and conditions for being connected to the PowerStream distribution system.

The Embedded Generation Connection Overview is posted on the PowerStream website at www.powerstream.ca.

Subject to all applicable laws, PowerStream will make all reasonable efforts in accordance with the provisions of Section 3.5 to promptly connect to its distribution system a generation facility, which is the subject of an application for connection.

3.5.3 Connection of Micro-Generation Facilities

A Person who wishes to connect a micro-embedded generation facility to the PowerStream distribution system shall submit an application to PowerStream providing the following information:

a) the name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the proposed generation facility at the connection point;

b) the fuel type of the proposed generation facility;

c) the type of technology to be used; and

d) the location of the proposed generation facility including address and account number where available.

Where the proposed micro-embedded generation facility is located at an existing Customer connection, PowerStream shall, within 15 days of receiving the application, make an offer to connect or provide reasons for refusing to connect the proposed generation facility. PowerStream shall give the applicant at least 30 days to accept the offer to connect and shall not revoke the offer to connect until this time period has expired. PowerStream will not charge the Customer for the preparation of the Offer to Connect.

PowerStream shall make any necessary metering changes and connect the applicant's micro-embedded generation facility to its distribution system within 5 days of the applicant completing the following:

a) Provide PowerStream with a copy of the authorization to connect from the ESA;

b) enter into a Connection Agreement with PowerStream; and

c) pay PowerStream for the costs of any necessary metering changes.

3.5.4 Connection of Small, Mid-Sized and Large Generation Facilities

Subsection 3.5.4 applies to the connection to the PowerStream distribution system of an embedded generation facility, which is not a micro-embedded generation facility.

After a Person who is considering applying for the connection of a generation facility to the PowerStream distribution system has requested a preliminary meeting with PowerStream and has provided the required initial set of information, then PowerStream shall provide a time when its relevant employees are available to meet with the Person within 15 days of the Person requesting the meeting. For the purposes of this section, the following is the required "initial set of information":

a) the nameplate rated capacity of each unit of the proposed generation facility and the total nameplate rated capacity of the generation facility at the connection point;

b) the fuel type of the proposed generation facility;

c) the type of technology to be used; and

d) the location of the proposed generation facility including address and account number with the Distributor where available.

At the preliminary meeting, PowerStream shall discuss the basic feasibility of the proposed connection including discussing the location of its existing distribution facilities in relation to the proposed generation facility and providing an estimate of the time and costs necessary to complete the connection. PowerStream will not charge for its preparation for and attendance at the preliminary meeting.

A Person who wishes to apply for the connection of a generation facility to the PowerStream distribution system shall submit an application, pay their impact assessment costs (applicable to mid-sized and large generation facilities or small generation facilities where requested by PowerStream) and provide the following information:

a) any of the "initial set of information" which has not yet been provided to PowerStream;

b) a single line diagram of the proposed connection; and

c) a preliminary design of the proposed interface protection.

For a **small embedded** generation facility, where PowerStream believes that a system directly connected to its distribution system may be impacted by the proposed small embedded generation facility, PowerStream will advise the Customer of the costs to conduct any required impact assessment.

PowerStream shall provide the Customer with its results of its impact assessment of the proposed generation facility, a detailed cost estimate of the proposed connection, and an offer to connect within:

a) 60 days of the receipt of the application where no distribution system reinforcement or expansion is required; and

b) 90 days of the receipt of the application where a distribution system reinforcement or expansion is required.

For a **mid-sized** embedded generation facility, PowerStream shall provide the Customer with its impact assessment of the proposed generation facility within 60 days of the receipt of the application.

For a **large embedded** generation facility, PowerStream shall provide the Customer with its impact assessment of the proposed generation facility within 90 days of the receipt of the application.

The impact assessment shall set out the impact of the proposed generation facility on the PowerStream distribution system and any of its customers including:

a) any voltage impacts, impacts on current loading settings and impacts on fault currents;

b) the connection feasibility;

c) the need for any line or equipment upgrades;

d) the need for transmission system protection modifications; and

e) any metering requirements.

The Customer shall submit any material revisions to the design, planned equipment or plans for the proposed generation facility and connection with PowerStream. PowerStream shall then prepare a new impact assessment within the relevant time period as set out above.

In the case of an application for the connection of a mid-sized or large embedded generation facility, after receiving from PowerStream the impact assessment the applicant shall pay to PowerStream for the cost of preparing a detailed cost estimate of the proposed connection and enter into an agreement with PowerStream on the scope of the project. PowerStream shall then provide the applicant with a detailed cost estimate and an offer to connect by the later of 90 days after the receipt of payment from the applicant and 30 days after the receipt of comments from a transmitter or other Distributor that may have been advised under the following clause.

Within 10 days of receiving payment from the applicant for preparing a detailed cost estimate, PowerStream shall advise any transmitter or Distributor whose transmission or distribution system is directly connected to the PowerStream distribution system that it is preparing a detailed cost estimate for a proposed large or mid-sized embedded generation facility. PowerStream will use its discretion in advising impacted transmitter or Distributor when the detailed cost estimate involves a proposed small embedded generation facility.

After the applicant has entered into a connection cost agreement with PowerStream and has provided the detailed engineering drawings with respect to the proposal, PowerStream shall conduct a design review to determine if the detailed engineering plans are acceptable.

PowerStream has the right to witness the commissioning and testing of the connection of the generation facility to its distribution system. After the applicant has

a) informed PowerStream that it has received all necessary approvals;

b) provided PowerStream with a copy of the Certificate of Inspection from the ESA; and

c) entered into the appropriate Connection Agreement;

d) PowerStream has received the Authorization to Connect from ESA, and

e) PowerStream has issued the connection order,

PowerStream shall act to connect the generation facility to its distribution system in accordance with this COS.

Subject to any delays in commissioning and testing of the generation facility, which may be beyond the control of PowerStream, PowerStream shall connect a proposed small embedded generation facility within:

a) 60 days of the applicant taking the steps set out above, where no distribution system reinforcement or expansion is required; and

b) 180 days of the applicant taking the steps set out above, where a distribution system reinforcement or expansion is required.

Information on the process for connecting a generation facility to a distribution system is set out in Appendix F.1 of the DSC.

3.5.5 Technical Requirements

The Customer shall ensure that the connection of its generation facility to the distribution system does not materially adversely affect the safety, reliability and efficiency of the PowerStream distribution system. New or significantly modified generation facilities shall meet the technical requirements specified in Appendix F.2 of the DSC.

The Customer with an embedded generation facility connected to the PowerStream distribution system (other than a micro-embedded generation facility) shall reimburse PowerStream for any damage to the distribution system or increased operating costs that may result from the connection of a generation facility.

A Customer with a generation facility connected to the PowerStream distribution system shall include in the connection agreement and upon request by PowerStream provide satisfactory evidence of a regular, scheduled maintenance plan that ensures that the Generator's connection devices, protection systems and control systems are maintained in good working conditions.

PowerStream may determine that equipment that was deemed to be in compliance with the technical requirements of the DSC as noted in the immediately preceding paragraph is not in actual compliance with the technical requirements due to any of the following conditions:

a) a material deterioration of the reliability of the distribution system resulting from the performance of the Generator's equipment; or

b) a material negative impact on the quality of power of an existing or a new customer resulting from the performance of the Generator's equipment; or

c) a material increase in Generator capacity at the site where the equipment deemed compliant is located.

In such a case, PowerStream will provide the Customer with rules and procedures for requiring such equipment to be brought into actual compliance. The Customer shall then bring its equipment into actual compliance with the technical requirements and within a reasonable time period specified by PowerStream.

When a Customer with an embedded generation facility is connected to the PowerStream distribution system, the Customer shall provide an interface protection that is capable of automatically isolating the generation facility from the PowerStream distribution system under the following situations:

a) internal faults within the Generator

b) external faults in the PowerStream distribution system

c) certain abnormal system conditions, such as over/under voltage, over/under frequency.

The Customers shall disconnect the embedded generation facility from the PowerStream distribution system when:

a) a remote trip or transfer trip is included in the interface protection, and

b) the Customer effects changes in the normal feeder arrangements other than those agreed upon in the operating agreement between PowerStream and the Customer.

3.5.5.1 Metering for Embedded Generation

The Embedded Generator shall consult with PowerStream for all metering installations on embedded generators. The Embedded Generator shall pay all costs associated with such metering. The Embedded Generator shall provide PowerStream Metering with the technical details of the Embedded Generation facility.

The Embedded Generator, if applicable, must provide PowerStream metering a single line diagram of all associated connected load at the facility, for the purpose of ensuring that all metering and rates are applied correctly.

Embedded Generation Facilities that receive energy, such as for station use of back-up supply shall be placed in the appropriate Rate class and billed for the energy consumed.

The Embedded Generator must have a meter or a metering installation in accordance with the DSC and PowerStream Metering Standards installed.

3.5.6 Net Metering Program for an Embedded Generation Facility

As a way to encourage conservation, PowerStream has established a Net Metering policy for eligible customers wishing to participate in the Net Metering program. Eligible customers with specific generation facilities may reduce their net energy costs by exporting surplus "generated" energy back onto the utility distribution system for credit against the energy the customer consumes from the distribution system.

Participation in the Net Metering Program is available to all PowerStream customers with a "Generator" that meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;
2. The electricity generated is conveyed to the customer's own consumption point without reliance on the PowerStream distribution system;
3. The maximum cumulative output capacity of the Generator does not exceed 500 kW; and
4. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof).

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro- Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the Generator size, as found in Section 3.5 - Embedded Generation Facilities.

The customer must have a bi-directional revenue meter that records energy flow in both directions.

The PowerStream policy for the Net Metering program is posted, as amended from time to time, on the PowerStream website at www.powerstream.ca.

3.5.7 Ontario Power Authority Standard Offer Program for an Embedded Generation Facility

In conjunction with the OPA Standard Offer Program (SOP), PowerStream has established its policy to encourage and promote greater use of renewable energy sources such as wind, solar, photovoltaic (PV), renewable biomass, biogas, bio-fuel, landfill gas, or drop in water elevation for generating electricity. Renewable energy electricity generation projects with a capacity of 10 MW or less that meet the program's requirements may be connected to the PowerStream distribution system in order to export electricity.

In most circumstances, generating facilities participating in the SOP will connect directly to the PowerStream distribution system at a voltage of 27.6 kV or less. Output from the generating facility shall be metered as follows:

a) for Generators of 10 kW or less and connected to the line side of the load meter, a bi-directional kWh meter must be installed to measure energy consumed and energy exported; and

b) for all other Generators, an interval meter must be installed.

The Generator will be solely responsible for any costs associated with the connection to the PowerStream distribution system and any required metering installation.

The PowerStream policy for the OPA Standard Offer Program is posted, as amended from time to time, on the PowerStream website at www.powerstream.ca.

3.6 Embedded Market Participant

Refer to Section 3.5

3.7 Embedded Distributor

An "Embedded Distributor" that receives electricity from PowerStream shall provide to PowerStream, as determined and required by PowerStream, load forecasts or any other information related to the Embedded Distributor's system load. PowerStream shall not require any information from another Distributor unless it is required for the safe and reliable operation of each other's Distribution Systems or in order to meet a Distributor's licence obligations.

Please also see Sections 2.1.4 Inspections Before Connections, 2.2 Disconnection

- End of Section –

SECTION 4 - GLOSSARY OF TERMS

4.1 Sources for definitions

A	*Electricity Act, 1998, Schedule A, Section 2, Definitions*
MR	Market Rules for the Ontario Electricity Market, Chapter 11, Definitions
TDL	Transitional Distribution License, Part I, Definitions
TTL	Transitional Transmission License, Part I, Definitions
DSC	Distribution System Code Definitions
RSC	Retail Settlement Code Definitions

4.2 Other Acronyms Defined in the Text

AAA:	Authorized Actual Amount
COS:	Conditions of Service
CSA:	Canadian Standards Association
DSC:	Distribution System Code
ESA:	Electrical Safety Authority
EUSA:	Electrical & Utilities Safety Association
IEC:	International Electro-technical Commission
IEEE:	Institute of Electrical and Electronics Engineers
IESO:	Independent Electricity System Operator
kV:	kilovolts
kVA:	kilovolt amps

OHSA: Ontario Occupational Health and Safety Act

OEB: Ontario Energy Board

OESC: Ontario Electrical Safety Code

OHSA: *Ontario Occupational Health and Safety Act*

OPA: Ontario Power Authority

OTC: Offer to Connect

POCS: Power Outage Communication System

RSC: Retail Settlement Code

SOP: Standard Offer Program

SSS: Standard Service Supply

STR: Service Transfer Request

V: Volts

4.3 <u>Glossary of Terms</u>

"Agreements" means any of the documents in Section 5 List of References

"Ancillary services" means services necessary to maintain the reliability of the IESO controlled grid including frequency control, voltage control, and reactive power and operating reserve services (MR, TDL, DSC)

"Apartment building" means a structure containing four or more dwelling units having access from an interior corridor system or common entrance

"Apparent power" means the total power measured in kilovolt Amperes (kVA)

"Application for service" means the agreement or contract with PowerStream under which electrical service is requested

"Back-up generator" means permanent or temporary generation that does not back feed into the Distributor's system

"Bandwidth" means a distributor's defined tolerance used to flag data for further scrutiny at the stage in the VEE (validating estimating and editing) process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 30 percent bandwidth means a current reading that varies 30 percent lower or higher than the measurement from an equivalent historical billing period. The VEE process will identify variances requiring further scrutiny and verification (DSC)

"Basic Connection Charge" means the charge for the Standard Allowance for Basic Connection consistent with the defined ownership demarcation point**.** The Basic Connection Charge is recovered through distribution rates.

"Board" or "OEB" means the Ontario Energy Board (A, TDL, DSC)

"Building" means a building, portion of a building, structure or facility

"Business days" means Mondays to Fridays, 8:00 am to 4:30 pm, and does not include hours outside those stated or weekends or statutory holidays or holidays prescribed by PowerStream

"Conditions of Service" or "COS" means the document developed by a distributor in accordance with subsection 2.4 of the Code that describes the operating practices and connection rules for the distributor (DSC)

"Connection" means the process of installing and activating connection assets in order to distribute electricity to a Customer (DSC)

"Connection assets" means that portion of the distribution system used to connect a Customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with that Customer (DSC)

"Connection period" means the five-year period following the date of initiation of energization of electric loads, connected on the Lands, as certified in writing from PowerStream – (Economic Model)

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate (A, MR, TDL, DSC)

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions (DSC)

"Demand" means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes (DSC)

"Developer" means a Customer, Customers or entity owning property for which new or modified electrical services are to be installed

"Disconnection" means a deactivation of Connection Assets that result in cessation of distribution services to a Consumer (DSC)

"Distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less (A, MR, TDL, DSC)

"Distribution losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows (DSC)

"Distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the Board under the *Ontario Energy Board Act, Section 78* (RSC, DSC)

"Distribution system" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main distribution system (A, MR, TDL, DSC)

"Distribution System Code" means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of the distributor which respect to the services and terms of service to be offered to Customers and retailers and provides minimum technical operating standards of distribution system (TDL, DSC)

"Distributor" means a person who owns or operates a distribution system (A, MR, TDL, DSC)

"Duct bank" means two or more ducts that may be encased in concrete used for the purpose of containing and protecting underground electric cables

"*Electricity Act" or "Electricity Act, 1998"* means the *Electricity Act, 1998, S.O. 1998, c.15, Schedule A* (MR, TDL, DSC)

"Electrical Safety Authority" or "ESA" means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority (A)

"Electric service" means the Customer's conductors and equipment for energy from PowerStream

"Embedded distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor (RSC, DSC)

"Embedded generator" or "embedded generation facility" means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system (DSC)

"Embedded retail generator" means an embedded generator that settles through a distributor's retail settlements system and is not a wholesale market participant (DSC)

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system (DSC)

"Energy" means the product of power multiplied by time, usually expressed in kilowatt-hours (kWH)

"*Energy Competition Act*" means the *Energy Competition Act, 1998, S.O. 1998, c. 15* (MR)

"Energy diversion" means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter readings, tap off load(s) before revenue meter or meter tampering

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth (DSC)

"Expansion" means an addition to a distribution system in response to a request for additional Customer connections that otherwise could not be made for example, by increasing the length of the distribution system (DSC)

"Extreme operating conditions" means extreme operating conditions as defined in the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition)

"Final reading date" means the date that the meter is last read prior to discontinuing or disconnecting service and represents the date that the account is closed

"Force Majeure" means events or causes beyond the reasonable control of PowerStream, including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes

"Four-quadrant interval meter" means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the Customer (DSC)

"General Service" means any service supplied to premises other than those designated as Residential and includes multi-unit residential establishments such as apartments buildings supplied through one service (bulk-metered)

"Generate", with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system (A, TDL, DSC)

"Generation facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operating of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose (A, MR, TDL, DSC)

"Generator" means a Customer who owns or operates a generation facility (A, MR, TDL, DSC)

"Good utility practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to the acceptable practices, methods, or acts generally accepted in North America (MR, DSC)

"Host distributor" means the registered wholesale market participant distributor who provides electricity to an embedded distributor (RSC, DSC)

"IESO-controlled grid" means the transmission systems with respect to which pursuant to agreements, the IESO has authority to direct operation (A, TDL, DSC)

"Interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis (RSC,DSC)

"Large user" means a Customer with a monthly peak demand of 5000 kW or greater, regardless the demand occurs in the peak or off-peak periods, averaged over 12 months

"Lies along" means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where a distributor has distribution facilities of the appropriate voltage and capacity

"Load transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point (DSC)

"Load transfer Customer" means a Customer that is provided distribution services through a load transfer (DSC)

"Main service" refers to PowerStream's incoming cables, bus duct, disconnecting and protective equipment for a Building or from which all other metered sub-services are taken

"Market Rules" means the rules made under section 32 of the *Electricity Act* (MR, TDL, DSC)

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Act*, 1980-81-82-83, c87, and Electricity and Gas Inspection Regulations (SOR/86-131 (DSC)

"Meter service provider" means an entity that performs metering services on behalf of a distributor, (DSC).

"Meter installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment (RSC, DSC)

"Meter socket" means the mounting device for accommodating a socket type revenue meter

"Metering services" means installation, testing, reading and maintenance of meters (DSC)

"Municipal" refers to the City of Vaughan, Town of Aurora, Town of Markham and the Town of Richmond Hill

"Normal operating conditions" means the operating conditions comply with the standards set by the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition)

"OEB" – see "Board"

"*Ontario Energy Board Act*" means the *Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B* (MR,DSC)

"Operating control" means the control exercised on an electrical facility by the exclusive authority to perform, direct or authorize the operation of any devices in that electrical facility. (Operating control is not synonymous with ownership).

"Operational demarcation point" means the physical location at which a distributor's responsibility for operational control of distribution equipment including connection assets ends at the Customer (DSC)

"Ownership demarcation point" means the physical location at which a distributor's ownership of distribution equipment including connection assets ends at the Customer (DSC)

"Person" includes an individual, sole proprietorship, partnership, unincorporated association, unincorporated syndicate, unincorporated organization, trust, body corporate, and a natural person in his or her capacity as trustee, executor, administrator, or other legal representative

"Point of supply", with respect to an embedded generator, means the connection point where electricity produced by the generator is injected into a distribution system (DSC)

"Power factor" means the ratio between Real Power and Apparent Power (i.e. kW/kVA)

"Primary service" means any service that is supplied with a nominal voltage greater than 750 volts

"Private property" means the property beyond the existing public street allowances

"Provincial" means the province of Ontario

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment (TDL, DSC)

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates (RSC, DSC)

"Reactive power" means the power component that does not produce work but is necessary to allow some equipment to operate, and is measure in kilovolt Amperes Reactive (kVAR)

"Real power" means the power component required to do real work, which is measured in kilowatts (kW)

"Regulations" means the regulations made under the *Ontario Energy Board Act* or the *Electricity Act,* (TDL, DSC)

"Residential Service" means a service that is less than 50kW supplied to single-family dwelling units that is for domestic or household purposes, including seasonal occupancy. At PowerStream's discretion, residential rates may be applied to apartment buildings with 6 or less units by simple application of the residential rate or by blocking the residential rate by the number of units

"Retail", with respect to electricity means, a) to sell or offer to sell electricity to a Consumer or b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or c) to act or offer to act as an agent or broker for a Consumer with respect to the sale or offering for sale of electricity (A, MR, TDL, DSC)

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, 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 Consumers transfer among competitive retailers (TDL, DSC)

"Retailer" means a person who retails electricity (A, MR, TDL, DSC)

"Secondary service" means any service that is supplied with a nominal voltage less than 750 Volts

"Service agreement" means the agreement that sets out the relationship between a licensed retailer and a distributor, in accordance with the provisions of Chapter 12 of the Retail Settlement Code (RSC)

"Service area", with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity (A, TDL, DSC)

"Service Layout" means a contract with PowerStream when a Customer request a new or upgraded electrical service

"Standard Allowance" means the Standard Allowance for Basic Connection is up to 30 meters of 200A, low-voltage overhead wire or equivalent credit for underground service, and also and transformation capacity or an equivalent credit for transformation equipment. The Standard Allowance does not include road crossings.

"Standard Supply Service Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under the *Electricity Act, Section 29* (TDL)

"Sub-service" means a separately metered service that is taken from the main Building service

"Supply voltage" means the voltage measured at the Customer's main service entrance equipment (typically below 750 volts). Operating conditions are defined in the Canadian Standards Association ("CSA") Standard CAN3-C235 (or latest edition)

"Temporary service" means an electrical service granted temporarily for such purposes as construction, real estate sales, trailers, et cetera

"Tenant" means a person, persons or entity that has entered into a tenancy agreement with the owner or agent of a building in accordance with the applicable regulations

"Termination" means a removal of connection assets that result in the service location no longer being connected to the distribution system, and results in a cessation of distribution services to a Consumer

"Transformer room" means an isolated enclosure built to applicable codes, PowerStream standards and which will house transformers and associated electrical equipment

"Transmission system" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose (A, MR, TDL, DSC)

"Transmission System Code" means the code, approved by the Board, that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with Customers, as well as establishing the standards for connection of Customers to, and expansion of a transmission system' (DSC)

“Transmit”, with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts (A, TDL, DSC)

“Transmitter” means a person who owns or operates a transmission system (A, MR, TDL, DSC)

“Unaccounted for energy,” means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and unmetered loads, energy theft and non-attributable billing errors (DSC)

“Unmetered loads” means electricity consumption that is not metered and is billed based on estimated usage (DSC)

“Variable Connection Charge” means the calculation of the costs associated with the installation of connection assets above and beyond the Standard Allowance. PowerStream may recover this variable connection fee, which shall be based on firm cost.

“Wholesale market participant”, means a person that sells or purchases electricity or ancillary services through the IMO-administered markets (RSC, DSC)

– End of Section –

SECTION 5 APPENDICES AND REFERENCES

Appendices:

Appendix A DSC Conditions of Service Template

Appendix B DSC Methodology and Assumptions for An Economic Evaluation

Appendix C PowerStream Electricity Licence #ED-2004-0420

Appendix D DSC Information in a Connection Agreement with a Customer

Appendix E PowerStream Consumer Security Deposit Policy

List of References:

All additional Tables, Forms, Rate Schedules, etc. mentioned in this COS can be found on the PowerStream website including but not limited to:

- Residential Subdivision Offer To Connect
- Commercial/Industrial New Services Offer To Connect
- Service Disconnect/Removal Form
- Rate Schedules
- Specific Service Charges
- Standards for Conditions of Service
    - Section 17 Underground
    - Section 25 Services & Metering
- Higher Reliability Service Offering
- Connection Agreement for Embedded Generator
- Operating Agreement

APPENDIX A

Distribution System Code

Conditions of Service Template

CONDITIONS OF SERVICE TEMPLATE

The Distribution System Code (DSC) requires that every distributor produce its own "Conditions of Service" document. The purpose of this document is to provide a means of communicating the types and level of service available to the customers within the distributor's service territory. The DSC requires that the Conditions of Service be readily available for review by the general public. In addition, the most recent version of the document must be provided to the Ontario Energy Board (OEB), who in turn will retain it on file for the purpose of facilitating dispute resolutions in the event that a dispute cannot be resolved without the Board's intervention.

This template has been prepared to assist distributors in developing their own "Conditions of Service" document based on current practice and the DSC. The template outlines the minimum requirements; however, distributors are encouraged to expand on the content to encompass local characteristics and other specific requirements. The form and general content of the Condition of Service document must be as required by the OEB. If a distributor chooses a different format, then the distributor must provide a cross-reference to the sections contained in this appendix.

The template also will serve as a reference for distributors that may require changes to their existing documents in order to reflect new changes prescribed by governing legislation, licenses, and codes.

The "Distribution Activities (General)" section contains references to services and requirements, which span across all customer classes. This section should cover such items as Rates, Billing, Hours of Work, Emergency Response, Power Quality, Available Voltage, etc.

The "Customer Class Specific" section contains references to services and requirements, which are specific to individual customer classes. This section would cover such items as Metering, Service Entrance Requirements, Delineation of Ownership, Special Contracts, etc.

Appendices to a distributor's Conditions of Service document should include sample Connection Agreements, along with any other documentation that requires more elaboration than may be described in each section of the document.

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SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

In this section, the distributor should identify their service territory as defined in the distributor's Licence.

1.2 Related Codes and Governing Laws

This section should reference any legislation that is applicable to the distributor - customer relationship.

1.3 Interpretations

This section should describe the rules for interpretation of the Conditions of Service document.

1.4 Amendments and Changes

This section should outline the process for making changes to this document. Include any public notice provisions.

1.5 Contact Information

This section should provide information on how a customer can contact the distributor. Include such items as:

- Address of the distributor,
- Telephone numbers,
- Normal business hours, and
- Emergency contact numbers.

1.6 Customer Rights

This section should outline the rights and obligations a customer or embedded generator has with respect to the distributor that are not covered elsewhere in this document.

1.7 Distributor Rights

This section should outline the rights a distributor has with respect to a customer or embedded generator that are not covered elsewhere in this document.

1.8 Disputes
Any dispute between customers or retailers and the distributor shall be settled according to the dispute resolution process specified in the Distributor Licence.
In this section, the Distributor should outline the Customer Complaint and Dispute Resolution processes that have been established as a condition of licence.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

This section should include information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in Section 3.

2.1 Connections

2.1.1 Building that Lies Along

In this section, the distributor should describe the standard connection allowance or charge used by the distributor in its service territory and describe any variable connection fees that would be charged beyond the standard allowance.

The distributor also may stipulate in this section other terms and conditions by which a customer requesting a connection must abide, as long as it is within the terms of this code.

2.1.2 Expansions / Offer to Connect

Under the terms of the DSC, a distributor has the Obligation to make an offer to connect any building that is in the distributor's service territory that cannot be connected without an expansion or enhancement, or "lies along" its distribution system, but may be denied connection for the reasons described in subsection 2.1.3 of the distributor's Conditions of Service.

The offer to connect must be fair and reasonable and be based on the distributor's design standard. The offer to connect also must be made within a reasonable time from the request for connection.

In this section, the Distributor should outline, in detail, the process followed to determine any required capital contributions. This section also should describe any fixed connection fees as well as variable connection fees, by customer class.

2.1.3 Connection Denial

The DSC sets outs the conditions for a Distributor to deny connections. The DSC lists reasons for which a Building that "lies along" a distribution line may be refused connection to that line. This section should describe reasons why a distributor may not be obligated to connect the customer and provide additional details, where relevant, about specific conditions that may result in a refused connection in accordance with this Code. For example, the criteria for establishing an unsafe connection or a connection, which adversely affects the system, should be further documented within the Conditions of Service.

2.1.4 Inspections Before Connections

In this section, the distributor should state the requirement for inspection prior to the commencement of electricity supply by the Electrical Safety Authority.

2.1.5 Relocation of Plant

This section should specify the distributor’s policy with respect to requests for relocation of plant and the conditions under which the requestor is or may be required to pay for the relocation of plant should be specified. Sharing arrangements also should be noted.

2.1.6 Easements

In this section, any requirements for easements should be described.

2.1.7 Contracts

This section should outline the types of contracts that are available for each type of customer, including standard, implied and special contracts. Connection agreements and operating agreements should be listed and referenced as appendices to the Conditions of Service, if applicable.

2.2 Disconnection

In this section, the distributor should specify under what circumstances it has the right or obligation to disconnect a customer. This section also should outline the business processes used by the distributor, including notification and timing provisions.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guaranty of Supply

In this section, the distributor should specify its limitations on the guaranty of supply. The distributor also should reference the provisions for “Powers of Entry” described in section 40 of the *Electricity Act, 1998.*

2.3.2 Power Quality

This section should outline the guidelines and policies to which the distributor will endeavor to adhere to in conveying electricity supply, such as service voltage guidelines and outage notification processes. This section also should indicate the process the distributor uses for handling voltage disturbances and power quality testing and remedial action.

This section also should include conditions under which supply of electricity to customers may be interrupted. Additionally, conditions under which the supply may become unreliable or intermittent should be described.

2.3.3 Electrical Disturbances

This section should outline the guidelines to which the Distributor and the Customer will be expected to adhere regarding electrical disturbances.

2.3.4 Standard Voltage Offerings

This section should specify the voltages that the distributor may provide to each type of Customer, based on their supply requirements. This section should include both the primary and secondary voltages that are available. Additionally, any physical or geographic constraints on a particular voltage, or conditions under which voltages may not be provided should be detailed in this section.

2.3.5 Voltage Guidelines

This section should specify what voltages the distributor’s customers can reasonably expect, with reference to CSA Standard CAN3-235 current edition.

2.3.6 Back-up Generators

Distributors should include the following statements in this section:

- Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back feed on the Distributor's system.

- Customers with permanently connected emergency generation equipment shall notify their Distributor regarding the presence of such equipment.

Any other requirements the Distributor imposes on customers with backup generation equipment should be described in this section.

2.3.7 Metering

This section should specify the options available to a Customer for metering equipment. The Distributor also should outline the technical requirements for meter installations including location and associated main switch.

2.3.7.1 General

Describe the Distributor's access to meter installation requirements here.

2.3.7.2 Current Transformer Boxes

Where current transformers are required, the Distributor should outline the technical requirements to be followed for such installations.

2.3.7.3 Interval Metering

Where interval metering is required or requested, the Distributor should outline the technical requirements to be followed for such installations. Included with the technical specifications should be the conditions under which interval metering will be supplied.

2.3.7.4 Meter Reading

This section should outline the requirements for access to meters for the purposes of obtaining readings and the process to be used if a reading is not obtained.

2.3.7.5 Final Meter Reading

This section should outline any requirements associated with obtaining a final meter reading on termination of a contract for service.

2.3.7.6 Faulty Registration of Meters

In this section, the Distributor should outline the process for dealing with metering errors.

2.3.7.7 Meter Dispute Testing

This section should outline the process by which a customer can dispute a meter measurement or read and seek redress.

2.4 Tariffs and Charges

2.4.1 Service Connection

The Distributor should outline the rates that have been established for providing the customer with a connection to the electrical distribution system and all services provided by the Distributor as per the rules and regulations laid out by all applicable codes.

2.4.2 Energy Supply

This section should outline the process the Distributor has established for the following:

- Provision of Standard Service Supply to the Customer, per the rules and regulations laid out in the Retail Settlement Code and the Standard Service Supply Code.

- Provision of Supply to the customer through a Retailer, per the rules and regulations laid out in the Retail Settlement Code.

- Wheeling of energy and all associated rates.

2.4.3 Deposits

This section should outline any deposit and prudential requirements the distributor has established for providing a customer with distribution services, supply through standard service supply or through a retailer, per the rules and regulations laid out in the Retail Settlement Code.

2.4.4 Billing

This section should outline the billing methods and billing cycles the distributor has established to provide a customer with distribution services, supply through standard service supply or through a retailer, per the rules and regulations laid out in the Retail Settlement Code.

2.4.5 Payments and Late Payment Charges

This section should outline payment methods that the distributor has established to provide the customer with distribution services, supply through standard service supply or through a retailer as per the rules and regulations laid out in the Retail Settlement Code.

2.5 CUSTOMER INFORMATION

The Conditions of Service shall describe the provision of information with respect to chapter 11 of the Retail Settlement Code. This specifies the rights of consumers and retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information. The Conditions of Service should include reference to include information subject to privacy regulations and load profile information.

Any processes for handling requests for information outside of the requirements of the Retail Settlement Code should be described in this section.

SECTION 3 CUSTOMER CLASS SPECIFIC

The Customer Class Specific section shall contain references to services and requirements, which are specific to individual customer classes. This section should cover such items as:

- Demarcation Point
- Metering.
- Service Entrance Requirements.
- Delineation of Ownership and Operational points of demarcation.
- Special Contracts.
- Other conditions specific to Customer class.

The following are examples of customer specific subsections. It is recognized that customer classifications are unique to each distributor. The distributor is not limited by these examples to the range and scope of their customer classifications. Each distributor therefore should review their current classifications and ensure that all of their existing customer classifications are adequately covered by the distributor's Conditions of Service document.

3.1 Residential

Include all items that apply specifically to residential customers not covered under the General section.

3.2 General Service

Include all items that apply specifically to general service customers not covered under the other sections, and broken down into:

3.3 General Service (Above 50 kW)

Include all items that apply specifically to general service customers (above 50 kW) not covered under the general service section. Describe the criteria to determine how a customer is classified as being above 50 kW.

3.4 General Service (Above 1000 kW)

Include all items that apply specifically to general service customers (above 1000 kW) not covered under the general service section. Describe the criteria to determine how a customer is classified as being above 1000 kW.

3.5 Embedded Generation

This section should include all terms and conditions applicable to the connection of embedded generation to the distributor (e.g., application process, engineering standards and operating agreements).

3.6 Embedded Market Participant

Criteria for a Customer that is classified as being a Market Participant needs to be established. This section should describe any specific requirements for customers that also are Market Participants.

3.7 Embedded Distributor

This section should include all terms and conditions applicable to the connection of an embedded distributor.

3.8 Unmetered Connections

This section will include all terms and conditions applicable to unmetered connections such as but not limited to the following;

3.8.1 Street Lighting

3.8.2 Traffic Signals

3.8.3 Bus Shelters

SECTION 4 GLOSSARY OF TERMS

The Conditions of Service document may contain a variety of terms that should be defined in the context of this document. Where possible, glossary terms should reflect definitions in existing documents that apply to the distributor, such as this Code, the distributor’s Licence and Standard Supply Service Code. The text of the Conditions of

Service document should be used to expand on these definitions as applicable to the distributor.

SECTION 5 APPENDICES

The following are samples of documents that could be appended to the Distributor's Conditions of Service document:

1. Economic Evaluation Model for Distribution System Expansion

2. Sample Operations Agreement between the distributor and an embedded generator and Standard Connection Agreements.

APPENDIX B

Distribution System Code

Methodology and Assumptions for

An Economic Evaluation

B.1 COMMON ELEMENTS OF THE DISCOUNTED CASH FLOW MODEL

To achieve consistent business principles for the development of the elements of an economic evaluation model, the following parameters for the approach are to be followed by all distributors.

The discounted cash flow (DCF) calculation for individual projects will be based on a set of common elements and related assumptions listed below.

Revenue Forecasting

The common elements for any project will be as follows:

(a) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below;

(b) Customer Revenue Horizon as specified below;

(c) Estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added – for various classes of customers, this should be carried out by class;

(d) Customer additions, as reflected in the model for each year of the Customer Connection Horizon; and

(e) Rates from the approved rate schedules for the particular distributor reflecting the distribution (wires only) rates.

Capital Costs

Common elements will be as follows:

(a) An estimate of all capital costs directly associated with the expansion to allow forecast customer additions.

(b) For expansions to the distribution system, costs of the following elements, where applicable, should be included:
- distribution stations;
- distribution lines;
- distribution transformers;
- secondary busses;

- services; and
- land and land rights.

Note that the “Ownership Demarcation Point” as specified in the distributor’s Condition of Service would define the point of separation between a customers’ facilities and distributor’s facilities.

(c) Estimate of incremental overheads applicable to distribution system expansion.

Expense Forecasting

Common elements will be as follows:

(a) Attributable incremental operating and maintenance expenditures – any incremental attributable costs directly associated with the addition of new customers to the system would be included in the operating and maintenance expenditures.

(b) Income and capital taxes based on tax rates underpinning the existing rate schedules.

(c) Municipal property taxes based on projected levels.

Specific Parameters/Assumptions

Specific parameters of the common elements include the following:

(a) A maximum customer connection horizon of five (5) years.[1]

(b) A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers.[2]

(c) A discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

(d) Discounting to reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted. The same approach to discounting will be used for revenues and operating and maintenance expenditures.[3]

1 For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board

2 For example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.

3 For certain projects Capital Expenditures may be staged and can occur in any year of the five-year connection horizon.

B.2 DISCOUNTED CASH FLOW (DCF) METHODOLOGY

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital
1. PV of Operating Cash Flow	=	P V of Net Operating Cash (before taxes) - P V of Taxes
a) PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied. Incremental after tax weighted average cost of capital will be used in discounting.
Net (Wires) Operating Cash	=	(Annual(Wires) Revenues - Annual (Wires) O&M)
Annual (Wires) Revenue	=	Customer Additions * [Appropriate (Wires) Rates * Rate Determinant]
Annual (Wires) O&M	=	Customer Additions * Annual Marginal (Wires) O&M Cost/customer
b) PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Tax	=	Municipal Tax Rate * (Total Capital Cost)
Total Capital Cost	=	Distribution Capital Investment + Customer Related Investment + overheads at the project level
Annual Capital Taxes	=	(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)
Annual Capital Tax	=	(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax – Annual Capital Tax)

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

2. PV of Capital	=	P V of Total Annual Capital Expenditures

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure	=	(for New Facilities and/or Reinforcement Investments + Customer Specific Capital + Overheads at the project level).This applies for implicated system elements at the utility side of the “Ownership Demarcation Line”.

Note: Above is discounted to the beginning of year one over the customer addition horizon

3. PV of CCA Tax Shield

P V of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of: $$\frac{[(\text{Income tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the ½ year CCA rule.

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

APPENDIX C

PowerStream Inc.

Service Territory Map


Powerstream GIS Department
March 01, 2006
N
E
S
W
Aurora
Richmond Hill
Markham
Vaughan
Highway 404
Highway 48
Highway 7
Highway 407
Highway 400
Highway 27
Highway 427
Regional Road 50
York - Durham Line
Reesor Road
9th Line
17th Avenue
18th Avenue
Markham Road
McCowan Avenue
Kennedy Road
Warden Avenue
Woodbine Avenue
Leslie Street
Bayview Avenue
Yonge Street
Bathurst Street
Dufferin Street
Keele Street
Jane Street
Weston Road
Pine Valley Drive
Kipling Avenue
Islington Avenue
Huntington Road
Elgin Mills Road East
Elgin Mills Road West
Major Mackenzie Drive East
Major Mackenzie Drive West
16th Ave
14th Ave
19th Ave
Steeles Ave
Steeles Ave W
Alden Rd
John Street
Centre Street
Carrville Road
Rutherford Road
Langstaff Road
Teston Road
Kirby Road
King - Vaughan Rd
Nashville Road
St John's Side Road
Wellington Street
Vandorf Side Rd
Henderson Side Rd
Bloomington Side Rd
Bethesda Side Rd
Stouffville Road
King Road
Jefferson Side Rd
Gamble Road
Pine Valley Dr
0
2
4
6
8
10 Kilometers
AGSI © Angus GeoSolutions Inc. and its Suppliers.
Power Stream
YOUR CURRENT CONNECTION

APPENDIX D

Distribution System Code

Information in a Connection Agreement with a Customer

A Connection Agreement must conform to this Code and a distributor's Conditions of Service. A Connection Agreement between a distributor and a customer connected to the distributor's distribution system, excluding embedded generators and connection with other distributors, should include the following information (examples provided in italics):

Contact Information:

- Date
- Account Number
- Date Customer's Responsibility Commences
- Name
- Service Address
- Mailing Address
- Home Phone No
- Business Phone No
- Type of Business
- SIC

The following clauses are suggested as examples:

The customer agrees to abide by the distributor's Conditions of Service, in effect and as amended from time to time.

The customer further agrees to:

(1) pay the distributor for the distribution services used by the customer at the location covered by this connection agreement from the date herein until such time as the customer no longer requires the service; and

(2) to commence payment in accordance with the approved rates prescribed attributed to the appropriate class rating to which the service applies, on or before the due date shown on the first account rendered and to pay all accounts either monthly or bi-monthly or as specified, thereafter.

Signature of customer (after reading the above and the General Conditions)

Witness

Signature of distributor (upon accepting the contract)

Date

General Conditions:

Space and Access
The customer agrees to provide suitable space for the distributor's meters, wires and where necessary poles, cables, transformers and all other appliances and equipment on the said premises and further agrees that no one who is not an agent of the distributor shall be permitted to remove, inspect or tamper with same, including seals and that the properly authorized agents of the distributor shall have reasonable access to the said premises for the purpose of reading, examining, preparing or removing their meters, wires, poles, cables, transformers and other appliances and equipment of the distributor and for the inspection of all the customer's appliances and wiring.

Responsibility for Equipment
Meters, wires, poles, cables, transformers and all other appliances and equipment of the distributor on the said premises shall be in the care and at the risk of the customer and if destroyed or damaged by fire or any other cause whatsoever other than ordinary wear and tear, the customer shall pay to the distributor the value of such meters, wires, poles, cables, transformers, appliances and equipment, or the cost of repairing or replacing same.

Disconnection
The customer hereby expressly authorizes and empowers the distributor at the distributor's option to remove the meter, wires, poles, cables, transformers and all other appliances and equipment installed at the distributor's expense and discontinue the supply of electricity and terminate this agreement whenever any bills for the said service are in arrears or upon violation by the customer of any of the terms and conditions of this agreement.

Reliability
The distributor agrees to use reasonable diligence in providing a regular and uninterrupted service but does not guarantee a constant service or the maintenance of unvaried frequency of voltage and will not be liable in damages to the customer by reason of any failure in respect thereof. It is the customer's responsibility to provide for the protection of his equipment. From voltage variations, transient operations and single phasing.

Conditions of Service
The building must be supplied with electrical energy according to the distributor's Conditions of Supply.

Binding
This agreement shall not be binding upon the distributor until accepted by it through a designated officer and shall not be modified or affected by any promise, agreement or representation by any agent or employee of the distributor unless incorporated in writing into this agreement before such acceptance.

Maintenance Requirements

The customer shall maintain the installation in efficient condition with proper devices, according to the requirements and rules of the Electrical Safety Authority (ESA). If the electrical installation is found to be inadequate, the supply of electricity shall be suspended until such time as the above requirements are complied with.

Security Deposit

The distributor reserves the right to require security for payment of future charges.

Termination

This agreement shall continue in force until terminated by notice in writing given by either party hereto thirty days in advance of termination.

Successors

It is agreed that the signatures of the parties hereto shall be binding upon their successors or assigns and that the vacating of the premises herein named shall not release the customer from this agreement except at the option and by written consent of the distributor.

Approval of Equipment

All electrical and mechanical equipment such as motors and welders used by the customer shall be subject to the reasonable approval of the distributor and the customer shall so take and use the electrical energy as not to endanger the apparatus of the distributor or cause any wide or abnormal fluctuations of its line voltage. Where practical, equipment with the highest power factor should be chosen and motors should be sized to match the load. Equipment performance characteristics shall be in accordance with the distributor's Conditions of Service.

Fire or Other Casualty

In case fire or other casualty occurs in said premises, rendering the premises wholly unfit for occupancy, the supply of electricity shall thereupon be suspended until such time, within said contract period, as the wiring shall have been repaired and approved by the ESA.

APPENDIX E

PowerStream Inc.

Consumer Security Deposit Policy

Background

On February 3, 2004 the Ontario Energy Board (OEB) amended the Distribution System Code (DSC) pertaining to Consumer Security Deposit Policies – RP-2002-0146 for the purpose of achieving more consistency in credit management practices. PowerStream is in compliance with the revised code and has filed a copy of the Conditions of Service with the OEB including the revised security deposit policy.

Purpose

To comply with the DSC as it pertains to Consumer Security Deposits as compliance is a condition of license. This policy establishes a consistent method of applying and administering Security Deposits among various customer classes as set out in the DSC while mitigating PowerStream's financial risks relating to customer billing.

Regulatory References/Codes/Standards

Ontario Energy Board – Distribution System Code

1.0 RESIDENTIAL DEPOSITS

1.1 New Residential

1.1.1 New residential customers not previously established within PowerStream Inc.'s service territory will not be required to pay a security deposit.

1.2 Existing Residential

1.2.1 Existing residential customers including those moving within PowerStream Inc.'s service territory are required to pay a security deposit if they have not maintained a **Good Payment History** as described in section 3.1.

1.3 Exceptions to Residential Security Deposit Requirements

1.3.1 Residential customers will be exempt from paying a security deposit provided they maintain a **Good Payment History** as defined in section 3.1.

2.0 GENERAL SERVICE DEPOSITS

2.1 General Service Customers

2.1.1 All general service customers will be required to pay a security deposit unless they qualify for an exemption as per section 2.2.

2.2 Exceptions to General Service Security Deposit Requirements

2.2.1 PowerStream Inc. will not require a security deposit from general service customers;

a) When the customer has achieved a **Good Payment History** as defined in section 3.1.

b) When a customer provides a letter from another electricity or gas distributor in Canada confirming a good payment history with that distributor for the most recent time period set out in section 3.1. The letter must be received by the due date of the *request for deposit* and the entity must be identified exactly as the application for service.

c) A customer, other than a customer in a >5000kW demand rate class, provides a satisfactory credit check from a recognized credit rating agency, made at the customer's expense.

d) From Federal, Provincial and Municipal Governments or agencies.

e) From a bank as defined in the *Bank Act, 1991, c.46.*

f) From School Boards.

3.0 ADMINISTRATION & DEFINITIONS

3.1 Good Payment History

3.1.1 A customer is deemed to have a **Good Payment History** unless the customer

a) Has received more than one disconnection notice or,

b) Has more than one cheque returned for insufficient funds or,

c) Has more than one pre-authorized payment returned for insufficient funds or,

d) A disconnect/collect trip has occurred

3.1.2 The time period that makes up the **Good Payment History** must be the most recent period of time and some of the time must have occurred in the past 24 months.

3.1.3 The minimum time period for a good payment history is as follows:

- Residential – 1 Year
- Non-residential <50 kW demand rate class – 5 Years
- All other non-residential rate classes – 7 Years

3.2 Calculation of Security Deposit Amount

3.2.1 The maximum amount of security deposit, which PowerStream Inc. may require a customer to pay, is calculated in the following manner:

a) Billing cycle factor x average monthly bill with PowerStream Inc. during the most recent 12 consecutive months within the past two years. The billing factors are:

i) 1.75 for bi-monthly billed customers

ii) 2.5 for monthly billed customers

3.2.2 Where there is no established historical electricity consumption information for the service premises, the deposit will be based on a reasonable estimate using information from a like property used for similar purposes.

3.2.3 If a customer is required to pay a deposit, PowerStream Inc. may reduce the calculated amount of the deposit by one-third if the customer agrees to participate in the Pre-Authorized Payment Plan.

3.2.4 Where the customer has more than one disconnection notice in the relevant 12 month period, the highest actual or estimated monthly load for the most recent 12 consecutive months within the past two years is used for the purpose of this calculation.

3.2.5 Notwithstanding 3.2.1, when a general service customer in any rate class other than <50kW demand rate class has a rating from a recognized credit rating agency, the maximum amount of security deposit shall be reduced in accordance with the following table:

Credit Rating *(Using Standard and Poor's rating terminology)*	**Allowable Reduction**
AAA- and above or equivalent	100%
AA-, AA, AA+ or equivalent	95%
A-, from A, A+ to below AA or equivalent	85%
BBB-, from BBB, BBB+ to below A *or* equivalent	75%
Below BBB- or equivalent	0%

3.2.5.1 Equivalent Ratings from other bond rating agencies would apply for the same reductions.

3.2.5.2 The commodity price used to calculate the security deposit in this case shall be the same as the price used by the Independent Electricity System Operator (IESO) for the purpose of determining maximum net exposures and prudential support obligations for market participants other than distributor's, low-volume consumers and designated consumers.

3.2.6 PowerStream Inc. shall provide a customer with the specific reasons for requiring a security deposit.

3.3 Form of Security Deposit Payment

3.3.1 Residential deposits will be in the form of cash, cheque or money order.

3.3.2 General service deposits will be in the form of cash, cheque, money order or an automatically renewing irrevocable letter of credit from a bank as defined in the *Bank Act, 1991, c.46* at the discretion of the customer. PowerStream Inc. will not accept third party guarantees.

3.4 Payments of Security Deposits

3.4.1 If requested, the customer will be permitted to pay the initial security deposit in equal installments over at least 4 months. A customer may choose to pay the security deposit over a shorter time period.

3.4.2 Electricity service is subject to collection action which may result in disconnection of service if the required deposit remains unpaid or a payment arrangement is not honoured.

3.4.3 PowerStream Inc. will accept payment of security deposits from a third party in whole or in part on behalf of the customer.

3.5 Review & Return of Security Deposit

3.5.1 PowerStream Inc. will review every customer's security deposit at least once per calendar year to determine if the entire amount of the security deposit is to be returned based on the **Good Payment History** described in section 3.1.

3.5.2 A customer may, no earlier than 12 months after the payment of a security deposit or the making of a prior demand for a review, request in writing a review to determine whether the entire amount of the security deposit is to be returned.

3.5.3 Security deposits returned as part of a review will be accomplished by crediting a customer's account or otherwise.

3.5.4 PowerStream Inc. shall promptly return any security deposit received upon closure of the customer account or when a customer changes from standard supply service (SSS) to a competitive retailer where the retailer is performing the billing function (retailer consolidated billing), subject to PowerStream Inc.'s right to use the security deposit to set off other amounts owing by the customer. If the customer moves within the same service area, the deposit and any accrued interest may be transferred to the new address, subject to the next scheduled review. The security deposit shall be returned to the customer within six weeks of the closure of an account.

3.5.4.1 PowerStream Inc. will not pay any portion of a customer's security deposit to a competitive retailer.

3.5.5 Where all or part of a security deposit was paid by a third party on behalf of the customer, PowerStream Inc. shall return to the third party the amount of the security deposit paid by the third party.

3.5.6 When conducting a review, PowerStream Inc. may adjust the maximum amount of a security deposit where a customer has not yet achieved the conditions of section 3.1 of this document when:

- there has been a change in either a customer's billing cycle factor or
- average monthly bill or

- credit rating or
- the deposit on file does not meet the requirements of this document

3.5.7 When conducting a review and where PowerStream Inc. determines that the maximum amount of a security deposit is to be adjusted upward, PowerStream Inc. will require the customer to pay this additional amount at the same time as the customer's next regular bill becomes due.

3.5.8 In the case of a customer in a >5000 kW demand rate class, where the customer is now in a position that it would be exempt from paying a security deposit, based on **Good Payment History** achieved as per section 3.1, PowerStream Inc. will return 50% of the security deposit held provided the deposit on file is in accordance with the deposit requirements of this document. In a situation where a customer's current deposit is less than 50% of the maximum amount permitted under section 3.2 of this document, then the deposit will not be refunded.

3.6 Interest

3.6.1 Interest will accrue monthly on security deposits made by way of cash, cheque or money order commencing on receipt of the total deposit required. The rate will be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated monthly. The interest accrued shall be paid out at least once every 12 months or on return or application of the security deposit or closure of the account, whichever comes first, and will be paid by crediting the account of the customer.

3.7 Retailer Prudentials

3.7.1 Prudential requirements from retailers will be calculated and collected as defined within section 8 of the *Retail Settlement Code* (Security Arrangements between Distributors and Retailers).

Schedule 14

LIST OF PROPOSED CHANGES TO POLICIES AND PROCEDURES ON ELECTRICITY SERVICES AND SERVICE CHARGES

PowerStream Inc. is not proposing any changes to Policies and Procedures on Electricity Services and Service Charges.

Schedule 15

PROPOSED WITNESS PANELS AND CURRICULA VITAE

Proposed Witness Panels and Curricula Vitae

Panel ID	Exhibit	Topic	Panel Member
Admin	A1, A2, A3	Overview of Application	Colin Macdonald, Paula Conboy
RB-1	B1-5-2 B1-5-4	Transformer Stations	Ted Wojcinski, Irv Klajman, Colin Macdonald
RB-2	B1-5-3	Corporate Head Office	Dianne Petrucci, Bill Schmidt, Paula Conboy
Rev	C1-1-2	Forecast Methodology	Vitalika Quenville, Dianne Petrucci, Paula Conboy
OM&A	D1-1-1	2009 OM&A Forecast	Tom Barrett, Neil Fernie, Colin Macdonald, Ed Benvenuto
Rates	I-2-1 I-3-1 I-6-2	LRAM/SSM, Smart Meters, Proposed Tariffs	Tom Barrett, Paula Conboy, Colin Macdonald

Thomas A. Barrett
Manager, Rate Applications

Mr. Barrett has over 30 years of experience in the financial accounting and reporting area. As an accounting software consultant with Deloitte Inc. from 1997 to 2003, Mr. Barrett worked with many electrical utilities in southern Ontario assisting them to meet their accounting, operational and financial reporting requirements. During this period, he also acted as interim Chief Financial Officer at Oshawa PUC in 2001 and Aurora Hydro in 2002. In 2003 Mr. Barrett joined Aurora Hydro as Chief Financial Officer. In 2005 Aurora Hydro was purchased by PowerStream and in 2006 when the Aurora Division was combined into PowerStream, Mr. Barrett was appointed to his current position of Manager, Rate Applications.

Mr. Barrett's past activities in the industry include being on the working committee for Specific Service Charges in the development of the 2006 EDR Handbook.

Mr. Barrett is a Chartered Accountant in the Province of Ontario. He received a Bachelor of Commerce from the University of Toronto in 1978.

Ed Benvenuto
Director, Customer Service

Mr. Benvenuto has 30 years of experience in the electrical distribution industry and began his career with North York Hydro in 1978 in their engineering design department and subsequently joined Markham Hydro in 1981. There he spent 10 years in engineering design as a Supervisor overseeing various overhead, underground, new service and standards departments. In 1991 Mr. Benvenuto was promoted to Manager of Customer Service were he was responsible for a variety of functions including Billing, Collections, Metering, New Commercial Services, Public Relations, Corporate Communications and Key Account management. In 2004 Markham Hydro and Hydro Vaughan, co-owners of Richmond Hill Hydro, amalgamated to form PowerStream which then subsequently purchased Aurora Hydro in 2005. Mr. Benvenuto was appointed to his current position of Director, Customer Service for PowerStream in 2004 and was responsible for the initial integration of staff and the conversion of all billing accounts from the predecessor utilities to one integrated billing system involving over 200,000 accounts. Recently, Mr. Benvenuto conceived an innovative staff development program specifically designed to meet the developmental needs of customer service professionals within the organization. Mr. Benvenuto is also the co-sponsor of PowerStream's Smart Meter coordination committee dealing with its Smart Meter deployment and integration program.

Mr. Benevento's past activities include developing a Time-Of-Use rate program for Markham Hydro in 1989, a Key Account program in 1992 which received an Innovation Award from the Municipal Electric Association (MEA) in 1993. Other achievements also include the appointment as Chairman of EnviroMark– A corporately sponsored and provincially funded initiative to promote energy management within the Town of Markham (1995 to 1997) as well as being a founding member of York Region's Habitat for Humanity initiative. Mr. Benvenuto holds University training certificates in Metering, Marketing, Customer Satisfaction Measurement and Key Account Management as well as certificates in Overhead and Underground System design through the APPA. Mr. Benvenuto has also been active as a member of various utility councils and committee's of the Electricity Distributors Association (EDA) and a member of PowerStream's United Way Committee.

Mr. Benvenuto Graduated from Centennial College in 1977 and is an Associate member of OACETT , Civil Technician, since 1978.

PAULA CONBOY
Director of Regulatory and Government Affairs

Paula Conboy is the Director of Regulatory and Government Affairs for PowerStream Inc., the local distribution company for the municipalities of Vaughan, Markham, Richmond Hill and Aurora. As Director, Paula is responsible for formulating and executing PowerStream's regulatory strategy in accordance with the Company's corporate objectives and acts as the primary resource on all regulatory matters. She is responsible for interpreting legislation, regulation, codes, government and regulatory policy as they apply to the Corporation. With over 15 years of experience in positions of increasing responsibility, Paula brings unique insight and perspective, having previously worked in the different areas of developing, advocating for and implementing public and regulatory policies.

She has been active in Electricity Distributors Association, Coalition of Large Distributors and is the current Chair of the Utility Sector Committee of the Ontario Energy Association.

Paula graduated from University of Guelph University with a Bachelor of Science and a Master's of Science in Agricultural Economics and has completed the Queen's Executive Program.

Neil Fernie
Director, Human Resource

Mr. Fernie has over 27 years of business experience, 18 of which has been in the electrical distribution industry. Mr. Fernie began his career with Toronto Hydro in 1981 where he entered the field of Human Resources in 1989.
In 1999 Mr. Fernie accepted a senior Human Resource role with the City of Toronto. While at the City Mr. Fernie was promoted to the position of Manager, Human Resources for the Water and Waste Water Department.
Following 2 ½ years with the City Mr. Fernie accepted a position with North York General Hospital as Manager, Labour Relations. Shortly after joining the Hospital Mr. Fernie assumed the role of Director, Human Resources. In October 2007 Mr. Fernie rejoined the electrical distribution industry when he accepted his current position of Director, Human Resources with PowerStream.

Mr. Fernie is currently a member of the Human Resources Professional Association of Ontario (HRPAO) and sits on the Board of Directors for the Toronto Chapter of the Canadian Mental Health Association. Mr. Fernie is also a frequent guest speaker at various Human Resource Conferences and Seminars.

IRV KLAJMAN
Manager, System Planning

Irv Klajman is the Manager, System Planning for PowerStream Inc., the local distribution company for the municipalities of Vaughan, Markham, Richmond Hill and Aurora. As Manager, System Planning, Irv is responsible for short and long term capacity planning, development of the asset condition assessment program, technical reviews of distribution system performance and long term load transfers. In over twenty-one years of utility experience, he has held varied positions of increased responsibility in project management, engineering design, operations and system planning. Irv has specialized in the areas of long term capacity planning. He has been active in Electricity Distributors Association working groups and has been a member of the Utility Advisory Council since its inception.

Irv graduated from the University of Western Ontario with a Bachelor of Engineering Science degree (electrical) and is a Registered Professional Engineer in the Province of Ontario.

COLIN MACDONALD
Director of Rates

Colin Macdonald is the Director of Rates for PowerStream Inc., the local distribution company for the municipalities of Vaughan, Markham, Richmond Hill and Aurora. As Director of Rates, Colin is responsible for rate applications, regulatory accounting and participating in the creation of regulatory strategies. In over twenty-five years of utility experience, he has held varied positions of increased responsibility in asset management, design, customer connections, fleet, facilities, finance and corporate planning. Colin has specialized in the areas of corporate strategy, business planning, project management, business case development and performance benchmarking. He has been active in Electricity Distributors Association and Canadian Electrical Association committees.

Colin graduated from McMaster University with a Bachelor of Electrical Engineering and Management, is a Registered Professional Engineer in the Province of Ontario and has completed the Queen's Executive Program.

DIANNE PETRUCCI
Manager, Rates & Revenue

Dianne Petrucci is the Manager, Rates and Revenue for PowerStream Inc., the local distribution company for the municipalities of Vaughan, Markham, Richmond Hill and Aurora. As the Manager, Rates and Revenue Dianne is responsible for revenue forecasting, budgeting and financial reporting, regulatory accounting and participating in the development of rate strategy and cases. With over sixteen years of utility experience, Dianne has held varied positions in accounting, corporate planning and regulatory. Dianne has specialized in revenue and rate development for the last five years.

Dianne graduated from the University of Toronto with a Bachelor of Arts Degree specializing in economics and commerce.

Vitalika Quenville
Assistant Regulatory Rates and Revenue Accountant

Mrs. Quenville started out in contracting roles for the Federal Government of Canada, gaining a Post-Graduate Diploma in research and statistical analysis. This was followed by joining PowerStream Inc. in 2005.

In her current role at PowerStream Mrs. Quenville specializes in load forecasting, cost of power and revenue projections, and regulatory accounting.

Fluent in English and Russian, Mrs. Quenville received a Master's degree in Economics from the University of Moscow in 1995. Currently, she is pursuing her CGA designation.

WILLIAM SCHMIDT
Director, IS

Mr. Schmidt has over 25 years of experience in the Information Technology Industry. Mr. Schmidt began his career with Canadian Pacific Railway. He spent 19 years working in the Information Technology Department, with the last 5 years of his career managing all data centers across North America, with a special focus on process rationalization, facility management, and Information Technology enhancements across all platforms. In 2001 Mr. Schmidt joined Indigo Books and Music, where he was the Director of Information Services. He headed a team responsible for all day to day operations, retail support, and merger transition activities as they related to synergies in Information Technology. In 2004 Mr. Schmidt joined PowerStream as the Director of Information Technology, being the only external Director hired by the amalgamated Richmond Hill, Vaughan, and Markham Hydro's.

Mr. Schmidt takes a very active roll within PowerStream, providing his support as the Vice Chair of the United Way, member of the Health and Safety Committee, and Vice Chair of the Social Committee. He also participates in many industry events sponsored by the CIO Council of Canada.

Mr. Schmidt received an Honours Bachelor of Arts Degree from the University of Toronto, and has received Executive Management Training from both The Richard Ivey School of Business and York University's Schulich School of Business.

Ted Wojcinski
Director, Engineering Planning

Mr. Wojcinski has over 27 years of experience in the electrical distribution industry. Mr. Wojcinski began his career with Toronto Hydro. He spent 11 years in the Distribution Planning and Design department in various project engineering and supervisory positions with a special focus on underground distribution engineering. In 1991 Mr. Wojcinski joined Hydro Vaughan as Operations Manager responsible for Construction, Station Maintenance, Protection & Control and System Control activities. In 2004 Markham Hydro and Hydro Vaughan, co-owners of Richmond Hill Hydro, amalgamated to form PowerStream and Mr. Wojcinski was appointed to his current position of Director of Engineering Planning.

Mr. Wojcinski's past activities in the industry include being Chair of the Institute of Electrical and Electronics Engineers(IEEE) Toronto Section(1991 – 1993) and being a member of the OEB PBR Task Force(1999) and Service Quality Task Force(2003-2004). He is currently the Past-Chair of the Electricity Distributors Association's Upper Canada District and is a member of the Electricity Distributors Association's Operations Council.

Mr. Wojcinski is a licensed Professional Engineer in the Province of Ontario and is a Senior Member of the IEEE. He received a Bachelor of Applied Science degree in Electrical Engineering from the University of Toronto in 1980 and Management and Administration(CIM) certification in 1988.

Schedule 16

BUDGET DIRECTIVES

The following memo dated June 25, 2007 was issued to start the development of the 2008 and 2009 OM&A budgets.

To: All Managers and Directors

Date: June 25, 2007

From: Geri Yin, Manager, Financial Services

Cc: Tony Cina, Director, Corporate Accounting& Taxation
John Glicksman, EVP & CFO
Dennis Nolan, EVP Corporate Services and Secretary
Milan Bolkovic, EVP & COO
Jack Dinsdale, EVP Asset Management
Ed Chatten, EVP, Corporate Performance

Subject: **2008-2009 OM&A Budgets Input Guideline**

Introduction

To align with the corporate strategic planning cycle and support our rate application based on a "forward test year", the 2008/2009 OM&A budget process has commenced in June this year. The approved 2007 budget is used as starting point. The year-to-date May actual OM&A results and 2007 forecast are also provided to you as reference in determining the budgets. The preparation of the 2008-2009 budgets is based on the 2007 Budget Methodology outlined in Appendix A. Below is 2008-2009 budget submission schedules. Your commitment to the Timeline is crucial to a successful completion of the budget submission. Any budget related questions should be directed to the Corporate Accounting Budget Team coordinator Grace Anlian or myself.

Timeline 2008-2009 Budget Submission

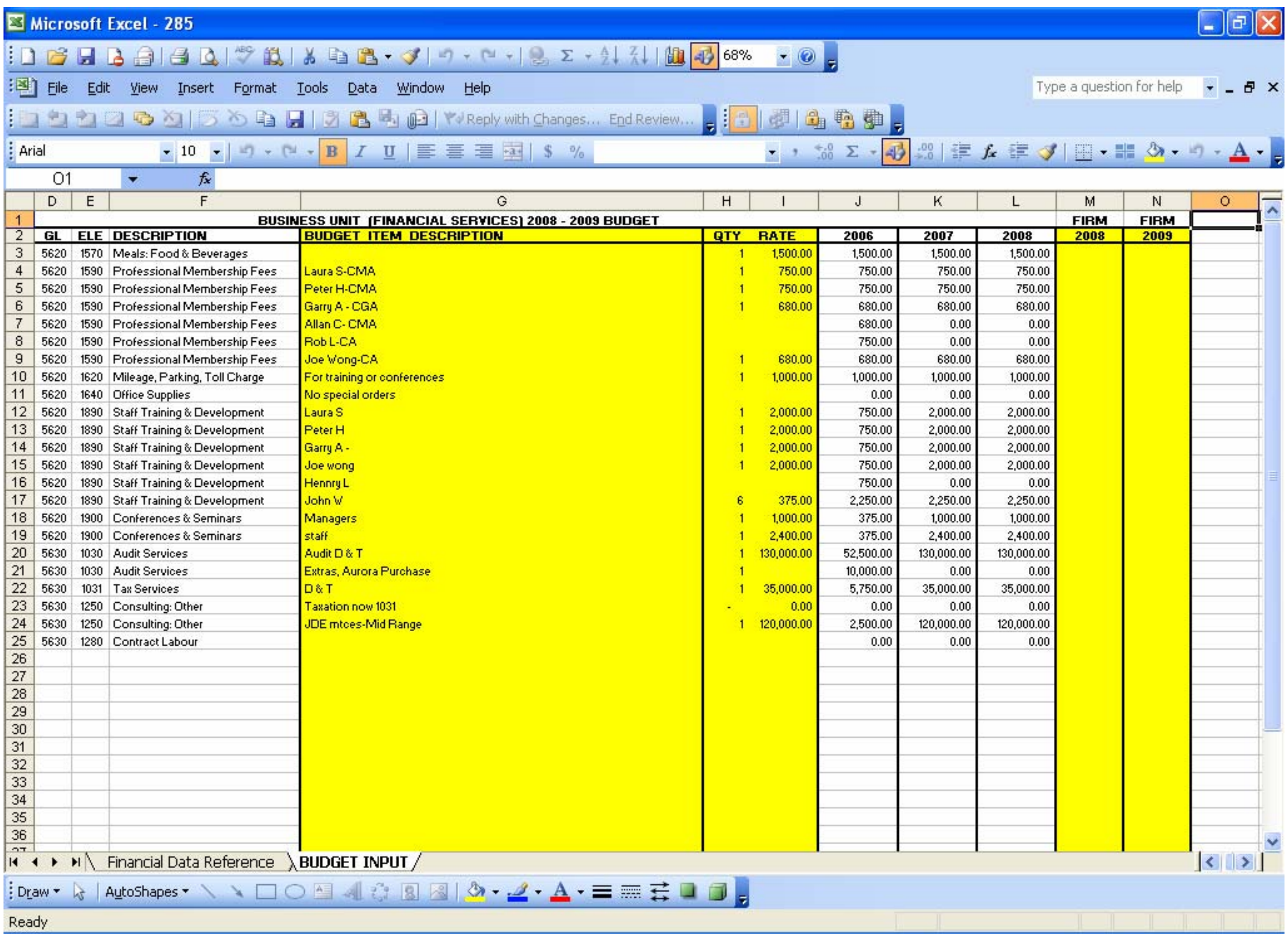
Date	Requirements	Responsibility
July 16	**Budget Request Forms/Equipment Schedule (IT, Fleet and Procurement) due to Financial Services**	**Each BU Director**
July 17-30	Review draft OM&A-Payroll budget with Directors	Budget Team/BU Directors
August 07	**Cut-off departmental 2008/2009 OM&A budget input**	**Each Department Manager**
August 14	Completion draft Unit, Division and Departmental budget report packages	Corp Accounting Budget Team
August 16-30	Review draft Departmental OM&A budget with each Director/EVP	Corp Accounting Budget Team/Directors/EVPs
September 07	Preliminary Departmental OM&A and Capital budget Due	Corp Accounting Budget Team
September 12	Budget update for Audit & Finance Committee approval	Corp Accounting/Corp Finance
October 12	Final 2008/2009 OM&A and Capital budget due	Corp Accounting Budget Team
November 1	EMT approval 2008/2009 budget	EMT

OM&A Template

The 2008-2009 OM&A budget templates for each Business Unit/Department are located on the shared drive (**K:**) under **08_Budg** and the applicable Parent Business Unit folder. For instance, Business Unit 285 is located at:

common on 'Psfs1' (K:)\ 08_Budg\200_Finance\285.xls

In the OM&A template, there are two tabs **Financial Data Reference** and **Budget Input**. The Budget Input tab provides 2006-2008 budgets previously entered. Please provide updated budget for 2008 and estimate for 2009 in the columns highlighted in yellow. The 2006-2007 actual/budget results and 2007 year-end forecast are provided in the Financial Data Reference tab for your reference. Please refer to the screenshot illustration below. If have any question related to the templates or you don't currently have access to the K: drive, please contact Grace Anlian at Financial Services.



	D	E	F	G	H	I	J	K	L	M	N	O
1	BUSINESS UNIT (FINANCIAL SERVICES) 2008 - 2009 BUDGET									FIRM	FIRM	
2	GL	ELE	DESCRIPTION	BUDGET ITEM DESCRIPTION	QTY	RATE	2006	2007	2008	2008	2009	
3	5620	1570	Meals: Food & Beverages		1	1,500.00	1,500.00	1,500.00	1,500.00			
4	5620	1590	Professional Membership Fees	Laura S-CMA	1	750.00	750.00	750.00	750.00			
5	5620	1590	Professional Membership Fees	Peter H-CMA	1	750.00	750.00	750.00	750.00			
6	5620	1590	Professional Membership Fees	Garry A - CGA	1	680.00	680.00	680.00	680.00			
7	5620	1590	Professional Membership Fees	Allan C- CMA			680.00	0.00	0.00			
8	5620	1590	Professional Membership Fees	Rob L-CA			750.00	0.00	0.00			
9	5620	1590	Professional Membership Fees	Joe Wong-CA	1	680.00	680.00	680.00	680.00			
10	5620	1620	Mileage, Parking, Toll Charge	For training or conferences	1	1,000.00	1,000.00	1,000.00	1,000.00			
11	5620	1640	Office Supplies	No special orders			0.00	0.00	0.00			
12	5620	1890	Staff Training & Development	Laura S	1	2,000.00	750.00	2,000.00	2,000.00			
13	5620	1890	Staff Training & Development	Peter H	1	2,000.00	750.00	2,000.00	2,000.00			
14	5620	1890	Staff Training & Development	Garry A -	1	2,000.00	750.00	2,000.00	2,000.00			
15	5620	1890	Staff Training & Development	Joe wong	1	2,000.00	750.00	2,000.00	2,000.00			
16	5620	1890	Staff Training & Development	Hennry L			750.00	0.00	0.00			
17	5620	1890	Staff Training & Development	John W	6	375.00	2,250.00	2,250.00	2,250.00			
18	5620	1900	Conferences & Seminars	Managers	1	1,000.00	375.00	1,000.00	1,000.00			
19	5620	1900	Conferences & Seminars	staff	1	2,400.00	375.00	2,400.00	2,400.00			
20	5630	1030	Audit Services	Audit D & T	1	130,000.00	52,500.00	130,000.00	130,000.00			
21	5630	1030	Audit Services	Extras, Aurora Purchase	1		10,000.00	0.00	0.00			
22	5630	1031	Tax Services	D & T	1	35,000.00	5,750.00	35,000.00	35,000.00			
23	5630	1250	Consulting: Other	Taxation now 1031	-	0.00	0.00	0.00	0.00			
24	5630	1250	Consulting: Other	JDE mtces-Mid Range	1	120,000.00	2,500.00	120,000.00	120,000.00			
25	5630	1280	Contract Labour				0.00	0.00	0.00			

Note: You will only be able to make changes to the columns highlighted in yellow. The prior 2008 budget figures need to be reviewed for budget reduction purpose. The updated 2008 budget should be entered under FIRM 2008 column. The estimate of 2009 should be populated under FIRM 2009 column.

The cut-off date for departmental OM&A input is Tuesday, August 7th.

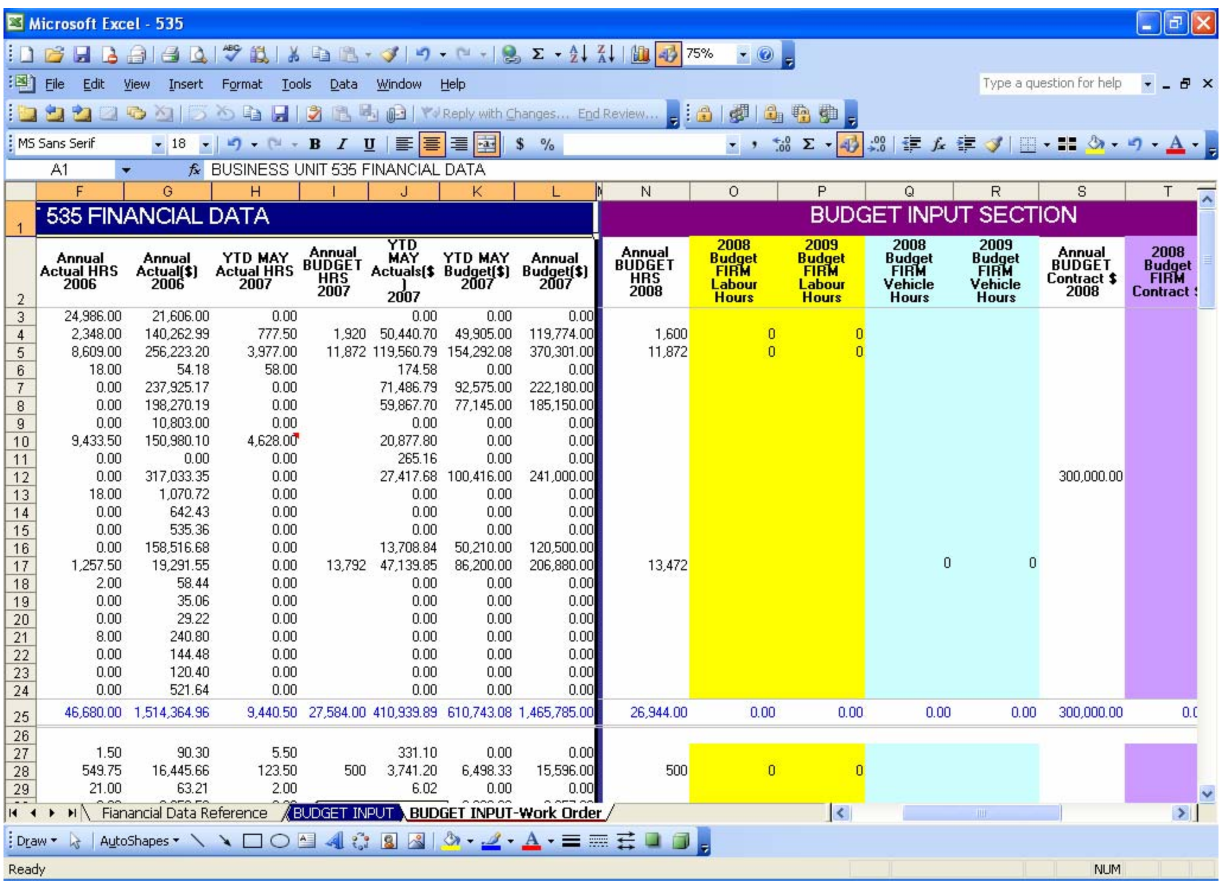
OM&A-Payroll

The payroll budget includes staffing costs and related burdens. The departmental headcounts, annual hours, hourly rate and vacation allotment, etc. will be input directly by Corporate Accounting in conjunction with HR. The staffing level is based on the approved 2007 budget. There will not be any new staff budgeted in 2008/2009 unless approved by the EMT. For budget purpose, the salary increase is set at 3.0% across board for both union and non-union staff. The payroll burden rates will remain unchanged from 2007 budget.

The departmental OM&A-Payroll budget for 2008/2009 will be completed by the Corporate Accounting Budget team/HR and reviewed with each Business Unit director during the period from July 17 to 30. We target to finalize the OM&A-Payroll budget by September 07th.

OM&A-Work Order

For Group/Outside A Business Units including Linemen, Inspection, Labourers, Electrical, Metering, Protection & Control (BU 435, 445, 475, 485, 535 and 575), the budgets are done at the work order level. In addition to the OM&A Template described above, these Business Units are required to provide detailed budgets including hours, material, contracts, etc. for each active work order. A sample of the Budget Input-Work Order template is presented below.



	F	G	H	I	J	K	L	N	O	P	Q	R	S	T
1	535 FINANCIAL DATA							BUDGET INPUT SECTION						
2	Annual Actual HRS 2006	Annual Actual($) 2006	YTD MAY Actual HRS 2007	Annual BUDGET HRS 2007	YTD MAY Actuals($) 2007	YTD MAY Budget($) 2007	Annual Budget($) 2007	Annual BUDGET HRS 2008	2008 Budget FIRM Labour Hours	2009 Budget FIRM Labour Hours	2008 Budget FIRM Vehicle Hours	2009 Budget FIRM Vehicle Hours	Annual BUDGET Contract $ 2008	2008 Budget FIRM Contract $
3	24,986.00	21,606.00	0.00		0.00	0.00	0.00							
4	2,348.00	140,262.99	777.50	1,920	50,440.70	49,905.00	119,774.00	1,600	0	0				
5	8,609.00	256,223.20	3,977.00	11,872	119,560.79	154,292.08	370,301.00	11,872	0	0				
6	18.00	54.18	58.00		174.58	0.00	0.00							
7	0.00	237,925.17	0.00		71,486.79	92,575.00	222,180.00							
8	0.00	198,270.19	0.00		59,867.70	77,145.00	185,150.00							
9	0.00	10,803.00	0.00		0.00	0.00	0.00							
10	9,433.50	150,980.10	4,628.00		20,877.80	0.00	0.00							
11	0.00	0.00	0.00		265.16	0.00	0.00							
12	0.00	317,033.35	0.00		27,417.68	100,416.00	241,000.00						300,000.00	
13	18.00	1,070.72	0.00		0.00	0.00	0.00							
14	0.00	642.43	0.00		0.00	0.00	0.00							
15	0.00	535.36	0.00		0.00	0.00	0.00							
16	0.00	158,516.68	0.00		13,708.84	50,210.00	120,500.00							
17	1,257.50	19,291.55	0.00	13,792	47,139.85	86,200.00	206,880.00	13,472			0	0		
18	2.00	58.44	0.00		0.00	0.00	0.00							
19	0.00	35.06	0.00		0.00	0.00	0.00							
20	0.00	29.22	0.00		0.00	0.00	0.00							
21	8.00	240.80	0.00		0.00	0.00	0.00							
22	0.00	144.48	0.00		0.00	0.00	0.00							
23	0.00	120.40	0.00		0.00	0.00	0.00							
24	0.00	521.64	0.00		0.00	0.00	0.00							
25	46,680.00	1,514,364.96	9,440.50	27,584.00	410,939.89	610,743.08	1,465,785.00	26,944.00	0.00	0.00	0.00	0.00	300,000.00	0.0
26														
27	1.50	90.30	5.50		331.10	0.00	0.00							
28	549.75	16,445.66	123.50	500	3,741.20	6,498.33	15,596.00	500	0	0				
29	21.00	63.21	2.00		6.02	0.00	0.00							

The cut-off date for departmental OM&A- work order input is Tuesday, August 7th.

Budget Request Form/Equipment Schedules

The Budget Request Form attached below is used as a means to collect the departmental requests for IT, Fleet and Building & Facility, including both Capital and OM&A expenditures.

It is required that each director consolidates his/her business units' budget requests in these areas and submits it to "**Financial Services"** once approved.

Once received, the Corporate Accounting Budget Team will forward it onto Tony D'Onofrio, IT (Basil Henriques), Procurement (Rob Zeni) and Fleet (Rick Willems) to jointly review and determine the proper input for the centralized Capital and OM&A budgets.

The Budget Request Form must be submitted by directors to Financial Services no later than Monday, July 16th.

The Budget Request Form is attached below.

K:\08_Budg\Budget Documentation\IT-Fle

Appendix A 2008/2009 Budget Methodology

The 2008/2009 budget is based on the 2007 approved OM&A budgets and 2007 year-end forecast. This base is further increased to incorporate inflation, customer growth, regulatory & legal requirements as well as corporate initiatives such as new business. In summary, the following budget principles are applied in 2008/2009 budget process:

1. Actual/budget 2006-2007 spending were provided to each department as reference in determining the 2008-2009 budget input

2. Staff count is based on the approved 2007 budget. No further additions unless approved by EMT.

3. For the Payroll budget, the followings were factored in the 2008/2009 Salary Rate:
    a. 3% Economic increase for both union and non-union staff
    b. Progression for qualified staff
    c. PIPS

4. All Management wage adjustments are budgeted to the applicable business unit

5. All Students are budgeted to the hiring business unit

6. For Group/Outside A Business Units including Linemen, Inspection, Labourers, Electrical, Metering, Protection & Control, the budgets are done at the work order level, allowing better planning, reporting and productivity & performance monitoring

7. Payroll burdens are adjusted to align with OEB requirement, i. e. overtime and PIP are removed from the scope of burdenable salary; payroll and engineering burdens currently applied to the payroll benefit pool are removed, etc.

8. The Budget Request Forms (Equipment Schedule) is used as a means to collect relevant departmental expenditures on IT, Procurement and Fleet such as

    a. Office Equipment
    b. Computer
    c. Software
    d. Vehicles
    e. Telephone and Radio

    Each director is required to consolidate the requests for his/her own business units and submit it to Financial Services who will then work with IT, Procurement and Fleet for developing the respective budgets

9. The budgets will be reviewed and discussed with each Business Unit director and EVP for their endorsement

10. Various departmental budget reports are designed and available for reporting
    - **Headcount Summary and Detailed Report** by Division/BU
    - **Payroll Budget Report** by Division/BU: including Regular, OT, Payroll/Engineering Burden, PIP, Allocation to Capital and Burden Pools
    - **Maintenance Work Oder Report** by department: detailed labor, OT, materials, contracts, burdens, etc.
    - **Hours Distribution Report** by BU: productive and non-productive hours for outside A business units
    - **OM&A Grand Summary Report** by Division/BU: including payroll and other expenses by GL account and element
    - **Burden Pool Summary and Detailed Report**: including Payroll, Engineering, Vehicle, Stores burden pools by Business Unit
    - **Applied Burden Summary and Detailed Report**:: including applied burdens on Payroll, Engineering (Labor, Contract and Materials), Stores and Vehicles by business Unit
    - **Allocation to Capital Report**: detailed amount allocated from OM&A to Capital budget

11. The Burden rates and allocation will remain the same as 2007 budget

Payroll Burden	**%**	**Element**	**Budget 2008-9**
Outside A	60	9150	60%
Outside B	30	9150	30%
All other	30	9150	30%
Students	10	9150	10%
Engineering Outside A	50	9160	50%
Other Burdens			
Stores handling	15	9180	15%
Vehicle	Rate applied	9170	Rate applied
Engineering on stores Material	20	9162	20%
Engineering on Contract Labor	50	9161	50%

Corporate Accounting Budget Team

Tony Cina: Head
Geri Yin: Lead
Grace Anlian: Coordinator
Ebrahim Hosseini: Budget Resource
Roger Bullock: Budget Resource

Schedule 17

FINANCIAL STATEMENTS – 2007 AUDITED (HISTORIC YEAR)

Financial statements of

PowerStream Inc.

December 31, 2007

PowerStream Inc.
December 31, 2007

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Deloitte.

Deloitte & Touche LLP
5140 Yonge Street
Suite 1700
Toronto ON M2N 6L7
Canada

Tel: 416-601-6150
Fax: 416-601-6151
www.deloitte.ca

Auditors' Report

To the Shareholders of
PowerStream Inc.

We have audited the balance sheet of PowerStream Inc. as at December 31, 2007 and the statements of earnings and comprehensive income and retained earnings and of 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, 2007 and the results of its operations and its cash flows for the year then ended, in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
March 28, 2008

PowerStream Inc.
Balance sheet
December 31, 2007
(in thousands of dollars)

	2007	2006
	$	$
Assets		
Current		
Cash	**23,634**	3,428
Restricted cash		
- current portion of customer deposits (Note 11)	**1,485**	1,022
Accounts receivable	**50,757**	61,801
Unbilled revenue	**59,352**	52,679
Inventory	**6,148**	5,407
Prepaids and other	**1,206**	566
	142,582	124,903
Property, plant and equipment (Note 5)	**429,392**	404,771
Other assets		
Restricted cash		
- non-current portion of customer deposits (Note 11)	**11,681**	12,657
Deferred debt issue costs,		
- net of amortization of $Nil (2006 - $2,511)(Note 4(d))	**-**	3,116
Intangibles, net of amortization of $1,428 (2006 - $1,206)	**2**	224
Goodwill	**32,988**	32,988
	616,645	578,659
Liabilities		
Current		
Accounts payable and accrued liabilities (Note 8)	**96,155**	89,515
Income taxes payable	**2,634**	955
Due to related parties (Note 9)	**16,748**	10,751
Liability for subdivision development	**4,144**	1,420
	119,681	102,641
Long-term liabilities		
Notes payable (Note 15)	**156,310**	148,157
Debentures payable (Notes 4(d) and 10)	**96,878**	100,000
Regulatory liabilities (Note 6)	**11,011**	14,554
Customer's deposits (Note 11)	**11,681**	12,657
Employee future benefits (Note 12)	**7,241**	6,322
Other liabilities	**4,691**	2,139
	287,812	283,829
Shareholder's equity		
Share capital (Note 14)	**149,433**	149,433
Contributed surplus (Note 14)	**14,324**	14,324
Retained earnings	**45,395**	28,432
	209,152	192,189
	616,645	578,659

Approved on behalf of the Board

Frank Scarpitti

_________ Director

_________ Director

PowerStream Inc.

Statement of earnings and comprehensive income and retained earnings year ended December 31, 2007

(in thousands of dollars)

	2007	2006
	$	$
		(Note 26)
Revenue		
Sale of energy	**489,777**	475,661
Distribution revenue	**114,580**	105,501
Other revenue (Note 16)	**10,477**	7,668
Total revenue	**614,834**	588,830
Cost of power purchased	**489,777**	475,661
	125,057	113,169
Operating expenses	**45,947**	40,503
Earnings before amortization, interest and income taxes	**79,110**	72,666
Amortization of capital assets and intangibles (net of $1,335; 2006 - $968 charged to other accounts)	**29,666**	28,500
Net interest expense (Note 23)	**14,196**	13,219
Income before income taxes	**35,248**	30,947
Income tax expense (Note 20)	**14,100**	11,465
Net earnings and comprehensive income for the year	**21,148**	19,482
Retained earnings, beginning of year	**28,432**	15,505
Change in accounting policy (Note 4(d))	**551**	-
Dividends	**(4,736)**	(6,555)
Retained earnings, end of year	**45,395**	28,432

PowerStream Inc.
Statement of cash flows
year ended December 31, 2007
(in thousands of dollars)

	2007	2006
	$	$
		(Note 26)
Net inflow (outflow) of cash related to the following activities		
Operating		
Net earnings and comprehensive income for the year	**21,148**	19,482
Adjustments to determine cash provided by operating activities		
Amortization of property, plant and equipment	**30,779**	29,127
Amortization of debt issue costs	**545**	554
Amortization of intangibles	**222**	341
Deferred interest on related party promissory notes	**8,153**	2,055
Employee future benefits	**919**	1,028
Decrease in regulatory liabilities	**(3,543)**	(761)
Gain on disposal of capital assets	**(4,493)**	(1,071)
Net change in non-cash operating working capital (Note 21)	**11,822**	(18,922)
	65,552	31,833
Financing		
Increase (decrease) in liability for subdivisions development	**2,724**	(503)
Increase (decrease) in due to related parties	**5,997**	(5,861)
Decrease in long-term customers' deposits	**(976)**	(721)
Increase in other liabilities	**2,552**	1,208
Dividends paid	**(4,736)**	(6,555)
	5,561	(12,432)
Investing		
Proceeds on disposal of capital assets	**9,891**	1,716
Intangibles	**-**	(4)
Decrease in short-term investments	**-**	6,608
Expenditure on capital assets, net of contribution of capital construction	**(60,798)**	(57,770)
	(50,907)	(49,450)
Net increase (decrease) in cash during the year	**20,206**	(30,049)
Cash, beginning of year	**3,428**	33,477
Cash, end of year	**23,634**	3,428

Supplementary cash flow information (Note 22)

1. Description of the business

PowerStream Inc. (the "Corporation") was incorporated on June 1, 2004, under the *Business Corporations Act* (Ontario) and is owned by the City of Vaughan through its wholly owned subsidiary, Vaughan Holdings Inc. and by the Town of Markham, through its wholly owned subsidiary, Markham Enterprises Corporation.

The principal activity of the Corporation is to distribute electricity in the service area of Vaughan, Markham, Richmond Hill and Aurora, in the Province of Ontario, under the license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval.

2. Electricity industry regulation

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.

PowerStream is required to charge its customers for the following amounts (all of which, other than the distribution rate, essentially represent a pass through of amounts payable to third parties):

(i) Electricity price and related rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

(ii) Distribution Rate. The distribution rate is designed to recover the costs incurred by PowerStream 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.
The volume of electricity consumed by PowerStream's customers during any period is governed by events largely outside PowerStream's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

(iii) Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to PowerStream for the transmission of electricity from generating stations to PowerStream's service area. Retail transmission rates are regulated by the OEB.

(iv) 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).

Any differences between the actual cost of electricity, transmission and wholesale market services and the amounts charged to customers are recorded in retail settlement variance accounts "RSVA amounts". These RSVA amounts are reviewed by the OEB and periodically rate adjustments are requested and approved by the OEB to "true up" the amounts charged to customers for these services.

Electricity distribution rates as described above are approved by the OEB and allow PowerStream to recover its reasonable costs and the OEB allowed market based rate of return.

As part of the restructuring of Ontario's electricity industry in 1999, the OEB allowed distributors to adjust their rates to incorporate a market based rate of return of 9.88%. This adjustment was made in three steps to lessen the rate impact on customers. Effective on each of March 1, 2001 and March 1, 2002, the OEB authorized the predecessor companies of PowerStream to increase revenues by $7,277.

2. Electricity industry regulation (continued)

In March 2005 PowerStream was allowed to increase rates to recover $7,277 representing the third and final adjustment to achieve the market based rate of return of 9.88%. The rate increase was effective April 1, 2005 and subjected PowerStream to a financial commitment to invest $7,277 in Conservation and Demand Management ("CDM") activities by September 30, 2008.

In 2006 the OEB approved distribution rates for the period May 1, 2006 to April 30, 2007 based on updated values for assets and costs, a deemed debt equity ratio of 60:40 and an allowed return on deemed equity of 9%. The OEB also allowed for recovery over the period May 1, 2006 to April 30, 2008 of regulatory asset and liability balances arising up to December 31, 2004.

In December 2006, the OEB announced the establishment of a multi-year electricity distribution rate-setting plan for distributors for the years 2007 to 2010, to streamline the process for approving distribution rates and charges. The OEB issued guidelines along with an Incentive Regulation Model ("IRM") to be used to calculate 2007 rate adjustments. The guidelines effectively adjusted Base Distribution Rates for inflation less a productivity factor.

On April 12, 2007, the OEB approved an IRM increase of 0.3% in PowerStream's distribution rates for the period May 1, 2007 to April 30, 2008.

PowerStream has applied to the OEB for an IRM increase in distribution rates of 0.3% for the period May 1, 2008 to April 30, 2009 and is waiting for approval.

The OEB has selected PowerStream to file a cost of service filing for its 2009 distribution rates. PowerStream will present its updated asset values and costs along with rate calculations to the OEB for approval of rates for the May 1, 2009 to April 30, 2010 period.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates and other permitted recoveries.

3. Significant accounting policies

The Corporation's financial statements are the representations of management prepared 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, issued under the authority of the Ontario Energy Board Act, 1998.

The financial statements reflect the following significant accounting policies:

(a) Rate setting

The Corporation is regulated by the OEB under authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers.

As the Corporation is regulated by the OEB, the timing of accounting recognition and measurement of assets and liabilities arising from rate regulation may differ from that otherwise expected under Canadian generally accepted accounting principles for non-rate regulated enterprises. Specifically:

(i) Capital and operating costs incurred in respect of the replacement of existing meters with smart meters have been deferred, and are being recovered along with accrued interest at OEB prescribed rates by temporary rate riders (Note 6).

(ii) The Corporation provides for amounts in lieu of corporate income taxes using the taxes payable method as permitted by The Canadian Institute of Chartered Accountants (CICA) for rate regulated entities.

3. Significant accounting policies (continued)

(a) Rate setting (continued)

(iii) The Corporation has deferred post-market opening retail settlement variances in accordance with Article 490 of the OEB Accounting Procedures Handbook (Note 6).

(b) Disclosures by entities subject to rate regulation

In 2005 the Corporation adopted the new accounting guideline "Disclosures by Entities Subject to Rate Regulation (AcG-19)". This regulation requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation.

(c) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on a basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

(ii) Other revenue

Other revenue related to sales 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.

(d) Inventory

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is stated at the lower of cost and replacement cost. Cost is determined on a weighted-moving average basis.

(e) Property, plant and equipment and amortization

Property, plant and equipment are recorded at cost and include contracted services, materials, labour, engineering costs, interest and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers and may be refunded by the Corporation based on economic evaluation (discounted cash flow), in accordance with the OEB Distribution System Code. Such contributions, whether in cash or in-kind, are offset against the related asset cost. Contributions in-kind are valued at their fair market value at the date of their contribution.

When identifiable assets, such as buildings, distribution station equipment and equipment and furniture are retired or otherwise disposed of, their original cost and related accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets such as transmission and distribution facilities is removed from the accounts at the end of their estimated service life.

(in thousands of dollars)

3. Significant accounting policies (continued)

(e) Property, plant and equipment and amortization (continued)

Amortization of property, plant and equipment is provided for on the straight-line basis over the estimated service life of the assets. Amortization of contributions from developers or customers is amortized at the rates corresponding with the useful lives of the related capital assets. The estimated service lives of the various assets used in calculating amortization are summarized below:

Buildings	10 to 60 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 property, plant and equipment under construction, assets 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 capital assets.

(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.

(g) Intangibles

Intangibles include corporate restructuring costs related to amalgamation. Intangibles are stated at cost and are amortized on a straight-line basis over three years.

(h) Regulatory assets and liabilities

Regulatory assets represent either costs that have been deferred or Retail Settlement Variances (RSVA) that it is expected will be recovered through future rates. RSVA arise from differences in amounts billed to customers and retailers and the cost to the Corporation that the OEB directs the distributor to account for. The Corporation accrues interest on certain regulatory assets and liabilities as allowed by the OEB.

The Corporation began recovery of regulatory assets on April 1, 2005 for deferred balances dating back to December 31, 2003. On April 28, 2006 the Corporation received approval from the OEB and subsequently implemented for May 1, 2006 the recovery of these regulatory assets. This final approval was for recovery of balances accrued at December 31, 2004 plus interest thereon accrued to April 30, 2006:

(i) For the Markham rate zone, recovery of retail and non-retail settlement variance account balances of ($3,859),
(ii) For the Richmond Hill rate zone, recovery of retail and non-retail settlement variance and balances of ($987),
(iii) For the Vaughan rate zone, recovery of retail and non-retail settlement variance balances of ($9,100), and
(iv) For the Aurora rate zone recovery of retail settlement variance balances of $3,300.

Recovery of the approved 2004 regulatory asset amounts ends April 30, 2008. Recovery of regulatory assets arising subsequent to 2004 will be considered by the OEB in PowerStream's 2008 and 2009 rate applications.

3. Significant accounting policies (continued)

(h) Regulatory assets and liabilities (continued)

The 2007 year end regulatory assets and liabilities are comprised principally of Smart Meter costs and retail settlement variances.

As at December 31, 2007, management has provided a "valuation allowance" against regulatory assets comprised principally of pension costs. Management continues to assess the likelihood of recovery of its regulatory assets and believes that it is probable that its regulatory assets, net of the valuation allowance, 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. Goodwill is not amortized but is tested for impairment annually 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.

(j) Pension and other post-employment benefits

The Corporation accounts for its participation in the Ontario Municipal Employees Retirement Fund ("OMERS"), a multi-employer public sector pension fund, as a defined contribution plan.

The Corporation actuarially determines the cost of other employment and 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-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at date of hire, and ended 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 future employee 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.

(k) Customer's deposits

Customer deposits are cash 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 customer balances at rates established from time to time by the Corporation.

(l) Payment in lieu of income taxes

In accordance with Ontario Regulation 162/01 made under the Electricity Act, 1998, the Corporation provides for payments in lieu of corporate income taxes using the taxes payable method. No provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers at that time.

3. Significant accounting policies (continued)

(m) Conservation and demand management

In accordance with the OEB, funds have been dedicated to spending on conservation and demand management initiatives spanning a four year period ending September 30, 2008. Any amounts collected in excess of the conservation and demand spending has been deferred and are recorded as part of regulatory liabilities.

(n) Measurement uncertainty

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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, inventory, regulatory assets/liabilities, goodwill and employee future benefits 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 or the Minister of Energy.

4. Changes in accounting policies

Current changes

Effective January 1, 2007, the Corporation was required to adopt the new accounting framework on financial instruments prescribed in the CICA Handbook Sections 3855-"Financial Instruments-Recognition and Measurement", 1530 – "Comprehensive Income", 3865 – "Hedges", 3861 – "Financial Instruments-Disclosure and Presentation", and the revised CICA Handbook Section 3251 – "Equity". These new Handbook Sections resulted in changes in the accounting for financial instruments.

(a) Financial instrument-recognition and measurement (Section 3855)

This Section established the standards for recognizing and measuring financial assets and financial liabilities and the standards for reporting gains and losses in the financial statements. Financial assets and liabilities are initially recorded at fair value. Subsequent measurement depends on how each financial instrument is classified on the balance sheet.

As of January 1, 2007, the Corporation has made the following balance sheet classifications in connection with its financial assets and financial liabilities:

Cash and customer deposits are classified as financial "Assets Held-for-Trading" and are measured at fair value.

Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost using the effective interest method.

Other non-current assets are classified as "Held-to-Maturity Investments" and are measured at amortized cost, which, after initial recognition, is considered equivalent to fair value.

Accounts payable, accrued liabilities, notes payable and debentures are classified as "Other Financial Liabilities" and measured at amortized cost using the effective interest method.

4. Changes in accounting policies (continued)

(b) Comprehensive income (Section 1530)

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of a financial instrument which has not been included in net income.

As the Corporation had no adjustments to other comprehensive income during the year-ended December 31, 2007, the adoption of this standard does not have any impact on the December 31, 2007 financial statements.

(c) Hedges (Section 3865)

These recommendations expand the guidelines outlined in Accounting Guideline 13 ("Acg-13"), Hedging Relationships. This section describes when and how hedge accounting can be applied, as well as disclosure requirements. Hedge accounting enables the recording of gains, losses, revenue and expenses from the derivative financial instruments in the same period as for those related to the hedged item. As at December 31, 2007, the Corporation has not engaged in any hedging transactions and none of its financial instruments can be designated for hedge accounting.

The adoption of this Section does not have any impact on the December 31, 2007 financial statements.

(d) Transaction costs - effective interest method (Section 3855)

Transactions costs will be capitalized to the cost of financial assets and liabilities classified as other than held for trading and the effective interest method used to amortize those transaction costs. The effective interest method requires the use of a constant yield rate based on expected cash flows to amortize transaction costs and record the related interest income/expense.

This new accounting policy was adopted retrospectively as of January 1, 2007 without restatement of the prior year's financial statements. The Corporation has adjusted its deferred debt issue costs related to the long-term debt (EDFIN debenture) to reflect the utilization of the effective interest method instead of the straight line method previously applied. As a result, retained earnings at January 1, 2007 was increased and debentures net of deferred debt issue costs was reduced by $551, respectively. The impact on the current year interest expense including amortization of deferred debt issue costs was not significant.

Effective January 1, 2007, debentures payable are reported at amortized cost net of unamortized deferred debt issue costs.

(e) Embedded derivatives

The Corporation reviewed active contracts as of the transition date for any embedded derivatives. Based on a review of the Corporation's financial instruments as at January 1, 2007, there were no embedded derivatives at that date that were required to be accounted for separately as derivatives.

4. Changes in accounting policies (continued)

Future accounting changes

(a) Inventories

In June 2007, the Canadian Institute of Chartered Accountants ("CICA") issued Section 3031, Inventories, replacing Section 3030, Inventories. The new Section will be applicable to financial statements relating to fiscal years beginning on or after January 1, 2008. Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2008. Under the new Section, inventories are required to be measured at the lower of cost and net realizable value. The Section provides updated guidance on the measurement and disclosure requirements for inventories and the impact of any write-downs to net realizable value.

The Corporation is currently evaluating the impact of the adoption of this new Section on its financial statements.

(b) Financial instruments

In December 2006, the CICA issued Section 3862, Financial Instruments - Disclosures; Section 3863, Financial Instruments - Presentation; and Section 1535, Capital Disclosures. All three Sections are applicable to financial statements relating to fiscal years beginning on or after October 1, 2007.

Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2008. Section 3862 on financial instruments disclosures, requires the disclosure of information about: i) the significance of financial instruments for the entity's financial position and performance and ii) the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. Section 3863 on the presentation of financial instruments is unchanged from the presentation requirements included in Section 3861. Section 1535 on capital disclosures requires the disclosure of information about an entity's objectives, policies and processes for managing capital as well as its compliance with any capital requirements.

The Corporation is currently evaluating the impact of the adoption of these new Sections on its financial statements.

(c) 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 the changes, the Corporation will be required to recognize future incomes 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 beginning January 1, 2009.

The Corporation is currently evaluating the impact of these changes on its financial statements.

(in thousands of dollars)

4. Changes in accounting policies (continued)

(d) Goodwill and intangible asset

In February 2008, the CICA issued Section 3064, Goodwill and intangible assets, replacing Section 3062, Goodwill and other intangible assets and Section 3450, Research and development costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Corporation will adopt the new standards for its fiscal year beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062.

The Corporation is currently evaluating the impact of the adoption of this new Section on its financial statements.

(e) International financial reporting standards

The CICA's Accounting Standards Board (AcSB) announced that Canadian publicly accountable enterprises will adopt International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB), effective January 1, 2011. IFRS will require increased financial statement disclosure. Although IFRS uses a conceptual framework similar to Canadian GAAP, differences in accounting policies will also need to be addressed. The Corporation is developing an implementation plan to allow for compliance with IFRS by the changeover date.

5. Property, plant and equipment

			2007	2006
	Cost	**Accumulated amortization**	**Net book value**	Net book value
	$	**$**	**$**	$
Land and land rights	**7,305**	**117**	**7,188**	6,780
Buildings	**5,034**	**538**	**4,496**	4,959
Transformer stations	**98,144**	**28,415**	**69,729**	65,248
Transformers and meters	**238,729**	**118,533**	**120,196**	119,960
Plant and equipment	**595,658**	**290,256**	**305,402**	293,776
Other	**28,200**	**17,440**	**10,760**	9,411
Construction in progress	**39,844**	**-**	**39,844**	29,444
	1,012,914	**455,299**	**557,615**	529,578
Capital contributions	**158,560**	**30,337**	**128,223**	124,807
	854,354	**424,962**	**429,392**	404,771

Included in property, plant and equipment costs is an amount of $3,456 (2006 – $2,063) related to an "allowance for the outlay of funds" employed during the construction period. In the absence of rate regulation interest income in the current year would have been lower by $1,393 (2006 - $1,278).

(in thousands of dollars)

6. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of the rate-making process and consist of the following:

	2007	2006
	$	$ (Note 26)
Regulatory assets		
Deferred Smart Meter costs	**12,869**	-
Deferred cash pension contributions	**2,374**	2,272
Deferred OEB annual cost assessments	**984**	933
	16,227	3,205
Provision for above regulatory assets	**(2,059)**	(2,059)
Regulatory assets	**14,168**	1,146
Regulatory liabilities		
Retail settlement variance accounts	**(23,848)**	(3,829)
Estimated over-recovery of payment in lieu of taxes	**(2,787)**	(1,807)
Regulatory assets recovery account	**2,443**	(3,004)
	(24,192)	(8,640)
Other regulatory liabilities	**(987)**	(7,060)
Regulatory liabilities	**(25,179)**	(15,700)
Net regulatory liabilities	**(11,011)**	(14,554)

(a) Regulatory assets

(i) Smart meter costs

As part of the Ontario Government's Smart Meter initiative to install smart meters throughout Ontario by 2010, PowerStream installed 82,000 Smart Meters in 2007. PowerStream has recorded the capital spending, incremental expenses and customer charges incurred in connection with Smart Meters in the deferral accounts established by the OEB.

In its August 8, 2007 Combined Proceeding decision, the OEB reviewed and approved recovery of expenses incurred to April 2007 for PowerStream and a number of other distributors. For costs after this, utilities are to apply for recovery in a cost of service rate application.

In the absence of this regulatory treatment, fixed asset costs would be increased by $14,184 with related amortization expense of $312. Other operating, maintenance and administrative expenses would be increased by $503. Other revenue would be increased by $1,531 and interest revenue would be lower by $129.

6. Regulatory assets and liabilities

(a) Regulatory assets (continued)

(ii) Deferred cash pension contributions account

The OEB has approved the establishment of a regulatory deferral account to record the OMERS pension costs for the period beginning January 1, 2005 up to April 30, 2006.

Under an unregulated business all costs would be expensed under Canadian GAAP. No expenses have been deferred in fiscal year 2007. Carrying charges continue to accrue on the deferred balance at the OEB prescribed rates. In the absence of this regulatory treatment, interest revenue would have been lower by $102 (2006 - $85).

(iii) Deferred OEB annual cost assessments account

The OEB has allowed the Corporation to defer a portion of the OEB annual cost assessments beginning January 1, 2004 and up to April 30, 2006. The Corporation has deferred the above noted costs in accordance with prescribed criteria in the OEB's Accounting Procedures Handbook ("APH").

Under OEB regulations, expenses were allowed to be deferred which would have been expensed under Canadian GAAP for unregulated businesses. No expenses have been deferred in fiscal year 2007. Carrying charges continue to accrue on the deferred balance at the OEB prescribed rates. In the absence of this regulatory treatment, interest revenue would have been lower by $51 (2006 - $64).

(b) Regulatory liabilities

(i) Retail settlement variance accounts

Retail settlement variances are variances that have occurred since May 1, 2002 when the competitive electricity market was declared open, to December 31, 2007, and have accumulated pursuant to direction from the OEB. Specifically, these amounts include:

(a) variances between the amount charged by the Independent Electricity System Operator ("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, as well as 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; and

(b) the differences between the amounts charged by the IESO and billed to consumers for energy costs.

Under OEB regulations, the retail settlement variances are allowed to be deferred which under Canadian GAAP would be recorded as revenue for an unregulated business. Under non regulated reporting, revenues would have been $18,567 higher in 2007 (2006 - $1,520) and interest expense would have been lower in 2007 by $1,940 (2006 - $105).

6. Regulatory assets and liabilities (continued)

(b) Regulatory liabilities (continued)

(ii) Estimated over-recovery of payment in lieu of taxes (PILs) variances are recorded as the differences resulting from the OEB approved PILs methodology (billed recovery) and the PILs proxy/allowance amount as determined. The cumulative amount of this variance, including carrying charges, as of December 31, 2007 is $2,787 (2006 - $1,807).

(iii) Regulatory assets recovery account

On May 1, 2006 PowerStream began recovering the 3rd phase of a 4 year regulatory asset recovery plan. These recoveries are based on final balances approved by the Ontario Energy Board reflecting costs to December 31, 2004 and carrying interest accrued to April 30, 2006. In 2007 the approved amounts were netted with the recoveries account as per OEB direction. The billed amounts are recorded in the regulatory assets recovery account and carrying interest is applied at the OEB prescribed interest rate for carrying charges. If regulated rates were not implemented the interest expense in 2007 would have been $210 (2006 - $320) lower.

(c) Other regulatory liabilities

In April 2005 the Corporation received approval to collect its final phase of market adjusted rate of return. These funds were to be collected over the 2005 rate year beginning April 1 2005 and ending April 30, 2006. These funds are to be dedicated to spending on conservation and demand management initiatives over a 4-year period ending in 2008. Consistent with revenue recognition principles and the revenue neutrality of the program, the Corporation has deferred amounts in 2007 in excess of the dedicated conservation and demand spending. The deferred balance as at December 31, 2007 was $1,000 (2006 - $6,478). A deferred amount of $5,478 was recorded in the current period. In 2006 a deferred amount of $1,142 was recorded.

(d) Provision

Management has determined that there is uncertainty concerning the future recovery of OMERS pension costs deferred for 2005 and 2006 based on the guidelines issued by the Ontario Energy Board on February 15, 2005. Based on this uncertainty, a provision against this deferred expense in the amount of $2,059 (2006 - $2,059) has been recorded.

Management will continue to assess the likelihood of recovery of its regulatory assets and believes that it is probable that regulatory assets/liabilities will be disposed of through a rate setting process sometime in the future. In the event that Management determines the recovery for these amounts is no longer probable, these amounts will be expensed in the period for which the determination is made.

(in thousands of dollars)

7. Bank indebtedness and credit facility

The Corporation requested and received an unsecured credit facility with a Canadian chartered bank and the related agreement was executed on April 27, 2007 for a term of five years, renewable annually. This credit facility agreement provides an extendible 365-day revolving credit facility of $125 million.

As at December 31, 2007, the Corporation had utilized $12 million of the credit facility to provide the IESO with a letter of credit for prudential support. 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.

The existing credit facility can be drawn upon by either direct advances, bearing interest at prime less 0.50% or Bankers' Acceptances, with a stamping fee of 20 basis points, or by way of letter of credit with a fee of 20 basis points per annum.

8. Accounts payable and accrued liabilities

	2007	2006
	$	$
Accounts payable - energy purchased	**42,309**	39,863
Current portion of customer's deposits	**1,485**	1,022
Deferred revenue	**2,383**	-
Other accounts payable and accrued liabilities (including construction deposits to be refunded within one year in the amount of $22,837 - 2006 - $17,003)	**49,978**	48,630
	96,155	89,515

9. Related party balances and transactions

The amount due to the Corporation of the City of Vaughan ("City") and the Corporation of the Town of Markham ("Town") is comprised of amounts payable to the City and Town and their wholly-owned companies established under the provisions of the Ontario Business Corporation Act in order to comply with provisions of provincial legislation enacted to restructure the publicly-owned electricity business in Ontario.

Components of the amounts due to related parties are as follows:

	2007	2006
	$	$
The Corporation of the City of Vaughan		
Net balance payable of inter entity transactions, without interest	**10,635**	6,422
The Corporation of the Town of Markham		
Net balance payable of inter entity transactions, without interest	**6,113**	4,329
	16,748	10,751

(in thousands of dollars)

9. Related party balances and transactions (continued)

Other significant related party transactions not otherwise disclosed separately in the financial statements, are summarized below:

	2007		2006	
	City of Vaughan	**Town of Markham**	City of Vaughan	Town of Markham
	$	**$**	$	$
Revenue				
Energy and distribution	**3,688**	**4,905**	3,591	3,571
Shared services	**1,537**	**1,228**	1,279	1,108
Expenses				
Facilities rental	**570**	**662**	517	602
Realty taxes	**201**	**142**	171	140
Operations	**824**	**207**	783	212

10. Debentures payable

	2007	2006
	$	$
6.45% unsecured Debentures due August 15, 2012, interest payable in arrears semi-annually on August 15 and February 15	**96,878**	100,000

In August 2002, the three predecessor corporations raised gross proceeds of $100,000 through a private placement offering. These corporations were three of five local distribution companies ("LDC") that participated in the Electricity Distributors Finance Corporation ("EDFIN") 10 Year Debentures Issued (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 LDC's 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 Corporation assumed the obligations of the three predecessor corporations pursuant to an assumption agreement dated June 1, 2004.

The debentures are recorded at amortized cost.

Interest expense, including amortization of deferred debt issue costs, was $6,995 (2006 - $7,004).

(in thousands of dollars)

11. Customers' deposits

	2007	2006
	$	$
Service deposits	**13,166**	13,679
Less amounts expected to be refunded within one year, included in accounts payable and accrued liabilities (Note 8)	**1,485**	1,022
	11,681	12,657

12. Employee future benefits

The Corporation pays certain health, dental and life insurance benefits on behalf of its retired employees. The Corporation recognizes these post-retirement costs in the period in which the employees rendered their services.

The benefits liability for the Corporation is being recorded in the accounts prospectively. Accordingly, the transitional obligation is being amortized over the average remaining service period of active employees of 11 years as determined by actuarial methodology.

The projected accrued benefit obligation for active employees and retirees as at December 31, 2007 is $9,839 and the expense for the period ended December 31, 2007 of $1,087 was based on an actuarial valuation as at January 1, 2005, using a discount rate of 5.0%.

Payments for the period ended December 31, 2007 are estimated to be equal to the estimated claims for extended health, dental benefits and life insurance in respect of retirees, and the assumed expenses and taxes associated with their benefits.

A reconciliation of the funded status of the Corporation's post-retirement benefit plan to the amounts recorded in the financial statements is as follows:

	2007	2006
	$	$
Accrued benefit obligation	**9,839**	9,269
Unamortized transitional obligation	**(623)**	(782)
Unamortized net actuarial losses	**(1,975)**	(2,165)
Accrued benefit liability	**7,241**	6,322

Details of the accrued benefit obligation are as follows:

	2007	2006
	$	$
Accrued benefit obligation, beginning of the year	**9,269**	8,734
Current service cost	**266**	254
Interest cost on obligation	**472**	445
Benefit payments	**(168)**	(164)
Accrued benefit obligation, end of the year	**9,839**	9,269

(in thousands of dollars)

12. Employee future benefits (continued)

The plan expense for the year is determined as follows:

	2007	2006
	$	$
Current service cost	**266**	254
Interest cost on obligation	**472**	445
Amortization of transitional obligation	**159**	315
Amortization of net actuarial loss	**190**	178
Plan expense	**1,087**	1,192

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation are as follows:

	%
Discount rate	**5.0**
Rate of compensation increase	**3.1**
Medical benefits costs escalation - hospitalization	**4.0-10.0**
Medical benefits costs escalation - extended health care	**4.0-10.0**
Dental benefits costs escalation	**4.0-5.0**

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 2007:

	Increase	Decrease
	$	$
Total service and interest cost	166	(53)
Accrued benefit obligation	1,901	(560)

13. Pension

The Corporation provides a pension plan for its employees through OMERS. OMERS is a multi-employer pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund. The Corporation incurred $2,194 of contribution expense during the year ended December 31, 2007 (2006 - $2,003).

(in thousands of dollars)

14. Share capital and contributed surplus

Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares. The issued share capital is as follows:

	2007	2006
	$	$
1035.0877 common shares	**149,433**	149,433

Of the total 1,035.0877 common shares issued 590 common shares are registered under Vaughan Holdings Inc. (wholly owned by The Corporation of the City of Vaughan) and 445.0877 common shares are registered under Markham Enterprises Corporation (MEC) (wholly owned by The Corporation of the Town of Markham).

Contributed surplus

Contributed surplus represents the difference between the total of the net assets contributed by The Corporation of the City of Vaughan and Markham Enterprises Corporation and the amount reported as stated capital in the financial statements of PowerStream Inc., upon amalgamation on June 1, 2004.

Closing adjustments for the Amalgamation of the Corporation which occurred on June 1, 2004, include a $1,706 payment to the Town of Markham to fulfill the intent of the Amalgamation Agreement. This payment occurred in 2005 and has been recorded as a reduction in contributed surplus.

15. Notes payable

	2007	2006
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**5,466**	1,100
Promissory note issued to the Town of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the Town of Markham	**4,742**	955
	156,310	148,157

On June 1, 2004 an unsecured 20 year term promissory note was issued to The Corporation of the City of Vaughan ("City") 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 Corporation of the Town of Markham ("Town") in the amount of $67,866. Interest thereon commenced on June 1, 2004 at an annual rate of 5.58%.

The two promissory notes are repayable 90 days following demand by the City or the Town, no earlier than January 1, 2009. These notes have been classified as long term as it is not the intent of the City or the Town to demand repayment within the next year.

At the request of the City of Vaughan and the Town of Markham, the interest will be deferred for eight quarters commencing October 1, 2006 for five years, subject to the same interest rate and conditions as the original note.

Interest of $4,497 on the note payable to the City of Vaughan and $3,902 on the note payable to the Town of Markham was charged to interest expense during the year.

16. Other revenue

During the year, PowerStream's excess fibre assets were sold to a third party. As part of the transaction, PowerStream will retain the fibre infrastructure required to support its current and future operational requirements necessary in serving its customers. The recorded gain on this sale is included in other revenue.

17. Commitments

Joint services agreement

Pursuant to a joint services agreement between PowerStream Inc. ("PowerStream") and the Corporation of the City of Vaughan ("City"), the Corporation charges the City, at agreed rates, for various administrative functions. In addition, the City performs certain shared services, which are charged to the Corporation. PowerStream has a similar arrangement with the Corporation of Town of Markham ("Town"). The net charges made for services under these agreements were $2,765 (2006 - $2,387).

Long-term operating leases

The Corporation rents buildings and facilities from the Corporation of the City of Vaughan and the Town of Markham under long-term operating leases. The Corporation has a lease with the Town of Markham terminating early 2008 and has exercised its option to renew a lease on a monthly basis with the City of Vaughan. For the period from January 1 to December 31, 2007, the rental for the buildings and facilities was approximately $1,232 (2006 - $1,119). The cost of the rent including both the rent charged under the operating leases and rent not covered by operating leases aggregated $1,619 (2006 - $1,455).

In November 2007, the Corporation entered into a lease agreement with a third party for the purpose of moving the operating centre and warehouse from the Markham location. The lease period is for 22 months from December 1, 2007 to September 30, 2009 with an option to extend for an additional period of 6 months. The total commitment of the lease, including the option period of 6 months is estimated to be $1,427 ($786 in 2008; $641 in 2009).

Contractual commitments

Markham TS#4

In 2007, the Corporation has engaged third parties to construct a new 230KV to 28KV Transformer Station in the Markham area – Markham TS#4 to serve the north side of Hwy 407 west of Warden. The estimated date of completion is December 2009. The total contract is approximately $7,492. As at the end of December 2007, $752 was spent on engineering design and construction.

New Head Office

The Corporation began its new head office construction in August 2006. The total building contract including ancillary costs is approximately $29,876. As at December 2007, $24,284 was spent on building construction and related ancillary costs. The building was completed and put into service in early 2008.

18. 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) *Other claims - Griffith et al v. Toronto Hydro-Electric Commissions 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 proceeding 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.

In 2007, Enbridge filed an application to the Ontario Energy Board ("OEB") to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of the said amounts 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.

At this time, it is not possible to quantity the effect, if any, on the financial statements.

19. Financial instruments and risk management

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.

Fair value of financial assets and liabilities

The review of all existing contracts substantiates that PowerStream does not currently have any contracts containing embedded derivatives that need to be accounted for separately using fair value.

The fair value of the Corporation's cash, accounts receivable, accounts payable and accrued liabilities and refundable customer deposits approximate their carrying amount because of the short term maturity of these instruments.

The fair value of the debentures payable was $105,823 as at December 31, 2007 based on quoted market prices.

The fair value of the Corporation's note payable for the Corporation of the City of Vaughan, the Corporation of the Town of Markham and due to related parties is not determined due to their related party nature and variable terms.

The Corporation is not exposed to significant interest rate risk as a result of its fixed rate debt and 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, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets.

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 $20,000 per incident.

(in thousands of dollars)

20. Corporate income taxes

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

	2007	2006
	$	$
Income from operations before PILs	**35,248**	30,947
Statutory Canadian federal and provincial income tax rate	**36.12%**	36.12%
Expected tax provision on income at statutory rates	**12,731**	11,178
Increase (decrease) in income taxes resulting from timing differences		
Amortization/CCA differences	**(435)**	(421)
Post employment benefits	**332**	371
Eligible capital expenditures	**(219)**	(98)
Other reserves	**596**	393
Other	**497**	47
Permanent differences	**(473)**	(139)
Adjustment of prior year's tax	**550**	-
Other	**521**	134
Provision for PILs	**14,100**	11,465

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future electricity rate revenues. As at December 31, 2007, future income tax assets of $37,478(consisted mostly of non-deductible reserves and the difference between the tax and book bases of capital assets), based on substantively enacted income tax rates, have not been recorded on the balance sheet.

21. Net change in non-cash operating working capital

	2007	2006
	$	$
Accounts receivable	**11,044**	(28,081)
Unbilled revenue	**(6,673)**	13,436
Income taxes payable	**1,679**	(161)
Inventory	**(741)**	367
Prepaid and other	**(640)**	(79)
Accounts payable, accrued liabilities and customer deposits	**7,153**	(4,404)
	11,822	(18,922)

(in thousands of dollars)

22. Supplemental cash flow information

	2007	2006
	$	$
Cash paid during the period for:		
Interest	**6,658**	14,603
Payments in lieu of taxes	**13,116**	13,538
Dividends	**4,736**	6,555

23. Net interest expense

	2007	2006
	$	$
Interest expense - notes and debentures payable	**15,394**	15,156
Interest expense - Other	**2,870**	1,129
Interest income	**(4,068)**	(3,066)
	14,196	13,219

Commencing January 1, 2007, PowerStream began to report interest expense net of interest income. Previously interest income had been reported as other revenue. The prior year's figures have been reclassified to the current basis of reporting.

24. 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, suites, 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.

24. Guarantees (continued)

(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.

25. Subsequent event

In January 2008, PowerStream secured a fifty million dollar, five year fixed rate loan facility with a major Canadian financial institution to fund on-going distribution capital requirements. The terms of the loan call for interest only payments at a rate of 5.08% per annum, payable monthly. The principal of the loan will be due upon maturity.

26. Comparative figures

Certain of the prior year's comparative figures have been reclassified to conform to the basis of presentation in the current year's financial statements.

Schedule 18

FINANCIAL STATEMENTS – 2008 ESTIMATE (BRIDGE YEAR)

POWERSTREAM INC.
Preliminary Income Statement
For the Period Ended June 30, 2008

	Actual YTD	Budget YTD	Variance YTD Fav/(Unf)	Budget Annual	Projected Annual	Projected Variance Fav/(Unf)
REVENUE						
Sales of Energy	236,049	247,979	(11,930)	507,325	507,325	-
Distribution Revenue	56,849	55,458	1,391	112,681	113,681	1,000
Other Revenue	2,536	2,600	(64)	6,580	6,288	(292)
Total Revenue	**295,434**	**306,037**	**(10,603)**	**626,586**	**627,294**	**708**
Cost of Power	236,049	247,979	11,930	507,325	507,325	-
Margin	**59,385**	**58,058**	**1,327**	**119,261**	**119,969**	**708**
EXPENSES:						
Board	1,401	1,190	(212)	2,379	2,379	-
Finance	6,624	7,003	379	14,005	14,651	(646)
Asset Management	4,967	5,451	484	10,901	10,209	692
Engineering Services	790	780	(11)	1,559	2,025	(466)
Building Facilities	978	715	(264)	1,429	1,735	(306)
Metering	524	635	111	1,269	1,159	110
CDM	218	-	(218)	-	395	(395)
Joint Services	(1,616)	(1,773)	(157)	(3,546)	(3,231)	(315)
Corporate Services	3,142	3,998	856	7,996	8,025	(29)
Corporate Performance	145	247	102	493	493	-
Corporate	2,845	2,498	(347)	4,996	6,146	(1,150)
Total OM&A Expense	**20,018**	**20,741**	**723**	**41,481**	**43,986**	**(2,505)**
EBITDA	**39,367**	**37,318**	**2,050**	**77,780**	**75,983**	**(1,797)**
Amortization	15,492	15,868	375	31,736	32,206	(470)
Interest	7,727	8,076	349	16,175	16,230	(55)
Earnings before Transition Costs	16,148	13,374	2,774	29,869	27,547	(2,322)
Transition Costs	-	-	-			
EBT	**16,148**	**13,374**	**2,774**	**29,869**	**27,547**	**(2,322)**
Amounts in lieu of income taxes	5,894	4,881	(1,013)	10,903	10,055	848
Net Earnings	**10,254**	**8,492**	**1,761**	**18,966**	**17,492**	**(1,474)**
Return on Equity - Deemed	**5.50%**			**9.00%**	**8.30%**	

Schedule 19

FINANCIAL STATEMENTS – 2009 FORECAST (TEST YEAR)

POWERSTREAM INC.

Pro-Forma Income Statement
For the period ended December 31, 2009
($000's)

	2009 Forecast
REVENUE	
Sale of Energy	510,537
Distribution Revenue	119,300
Other Revenue	5,000
Total Revenue	**634,837**
Cost of Power	510,537
Margin	**124,300**
EXPENSES	**47,200**
EBITDA	**77,100**
Amortization	35,600
Interest	17,700
EBT	**23,800**
Amounts in lieu of income taxes	7,900
Net Earnings	**15,900**

Schedule 20

FINANCIAL STATEMENTS – RECONCILIATION OF REGULATORY AND STATUTORY REPORTS

RECONCILIATION OF AUDITED FINANCIAL STATEMENTS AND APPLICATION

1.0 HISTORICAL YEAR (2006)

Table 1 compares PowerStream's 2006 Audited Financial Statements to the information for the 2006 Historical Year provided in PowerStream's 2009 EDR Application.

Table 1 – Comparison of 2006 Financial Statements to Rate Application

Item	2006 Fin. Statements, $000	2006 in Rate Application $000	Difference, $000	Table
Sale of Energy	475,661	475,661	0	
Distribution sales	105,501	105,225	(276)	***2***
Other revenue	7,668	7,022	(646)	***3***
	588,830	**587,908**	**(922)**	
Cost of Power Purchased	475,661	475,661	0	
Margin	**113,169**	**112,247**	**(922)**	
Operating Expenses	40,503	38,795	(1,708)	***4***
Earnings before amortization, interest and income taxes	72,666	73,453	787	
Amortization	28,500	28,167	(333)	***5***

Item	2006 Fin. Statements, $000	2006 in Rate Application $000	Difference, $000	Table
Capital Assets	803,690	767,707	35,983	***6***
Accumulated Amortization	398,919	398,455	(464)	***7***

Table 2 reconciles Distribution Revenue in the 2006 Audited Financial Statements and as presented in PowerStream's 2009 EDR application:

Table 2 –Distribution Revenue (2006)

Item	2006 FS, $000	2006 Rate Application $000	Notes
Distribution Revenue	**105,501**		
Reconciling Items			
Adjustment to distribution revenue		666	Due to use of normalized load and consumption and harmonized rates for the Full Year 2006 in rate model
Retail Services Revenue		(312)	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
STR Services		(5)	
SSS Admin Charge Revenue		(625)	
Total Adjustments		**(276)**	
Total in 2009 EDR model		**105,225**	

Table 3 reconciles Other Revenue in the 2006 Audited Financial Statements and as presented in PowerStream's 2009 EDR application:

Table 3 –Other Revenue (2006)

Item	2006 FS, $000	2006 Rate Application $000	Notes
Other Revenue	**7,668**		
Reconciling Items			
Misc. Service revenues / rent from electric utility		(153)	Excluding non-distribution charges (water)
Gain on Disposal of utility property		(994)	Excluding gain on sale of water heaters
Revenue and expense from non-utility operations[1]		(1,713)	Defined as "Other revenue – unclassified" in USoA
Interest Income		1,272	Netted against interest expense in FS
Retail Services Revenue		312	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
STR Services		5	
SSS Admin Charge Revenue		625	
Total adjustments		**(646)**	
Total in 2009 EDR model		**7,022**	

[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 2006 Audited Financial Statements and as presented in PowerStream's 2009 EDR application:

Table 4 – OM&A (2006)

Item	2006 FS, $000	Adjustments in 2006 Rate Application $000	Notes
Total OM&A	**40,503**		
Reconciling Items			
Sponsorships		(112)	Sponsorships not recovered through distribution rates
A&G Expenses		(10)	Expenses related to M&A preparation - not recovered through distribution rates
Charitable contributions		(11)	Donations not recovered through distribution rates
Other Distribution Expenses		(1,524)	Ontario Capital Tax is removed, since it is calculated as part of PILs
Rounding in FS		(1)	
Non-distribution expenses		(50)	Excluded from EDR model
Total adjustments		**(1,708)**	
Total in 2009 EDR model[2]		**38,795**	

[2] The slight difference of $1k is due to rounding in Financial Statements

The reconciliation of Amortization expenses as reported in the 2006 Audited Financial Statements and as provided in PowerStream's 2009 EDR application is presented in Table 5.

Table 5 – Amortization expense (2006)

Item	2006 Fin. Statements $000	Adjustments in 2006 Rate Application $000	Notes
Amortization expense	**28,500**		
Reconciling items			
		(231)	Adjustment to remove FMV of Aurora assets
		(102)	Amortization of non-distribution assets
Total Adjustments		**(333)**	
Total in 2009 EDR model		**28,167**	

A reconciliation of Capital Assets as reported in the 2006 Audited Financial Statements and as provided in PowerStream's 2009 EDR application is presented in the table below:

Table 6 – Capital Assets (2006)

Item	2006 Fin. Statements $000	Adjustments in 2006 Rate Application $000	Notes
Gross Assets	**952,723**		
		(29,444)	WIP excluded from NFA for Rate Base Calculation
		123	Adjustment to remove FMV of Aurora assets
Total Adjustments[3]		**(29,231)**	
Total in 2009 EDR model		**923,402**	
Contributed Capital ("CC")	**149,033**		
Total Adjustments		**6,662**	CC adjustment to remove FMV of Aurora assets
Contributed Capital in 2009 EDR model		**155,695**	
Gross Assets Net of CC	**803,690**	**767,707**	

[3] The adjustment of $713k for removing non-distribution assets offsets the adjustment made in 2007 continuity schedule for transportation assets disposal

A reconciliation of Accumulated Amortization as reported in the 2006 Audited Financial Statements and as provided in PowerStream's 2009 EDR application is presented in the table below:

Table 7 – Accumulated Amortization (2006)

Item	2006 Fin. Statements $000	Adjustments in 2006 Rate Application $000	2006 in Rate model $000	Notes
Accumulated Amortization	**398,919**			
		(249)		Accumulated adjustment for FMV of Aurora's assets
Non-distribution assets		(215)		Non-distribution items removed from Rate Base[4]
Total Adjustments		**(464)**		
Accumulated Amortization in 2009 EDR model			**398,455**	

[4] Street Lighting and Sentinel lighting rental units

2.0 HISTORICAL YEAR (2007)

Table 1 reconciles PowerStream's 2007 Audited Financial Statements to information for the 2007 Historical Year that is provided in this Application:

Table 1 – Comparison of Financial Statement to Rate Application

Statement of Income and Retained Earnings	2007 Financial Statement $000	Historical Year 2007 $000	Difference, $000	Table
Sale of Energy	489,777	489,777	0	
Distribution sales	114,580	107,812	(6,768)	**2**
Other revenue	10,477	7,396	(3,081)	**3**
	614,834	**604,985**	(9,849)	
Cost of Power Purchased	489,777	489,777	0	
Margin	**125,077**	**115,208**	(9,849)	
Operating Expenses	45,947	42,665	(3,282)	**4**
Earnings before amortization, interest and income taxes	79,110	72,543	(6,567)	
Amortization	29,666	29,885	219	**5**

Item	2007 Fin. Statements, $000	2007 in Rate Application $000	Difference, $000	Table
Capital Assets	854,354	824,889	(29,465)	***6***
Accumulated Amortization	424,962	428,370	3,408	***7***

Table 2 reconciles Distribution Revenue in the 2007 Audited Financial Statements and as presented in PowerStream's 2009 EDR application:

Table 2 –Distribution Revenue (2007)

Item	2007 FS, $000	2007 Rate Application $000	Notes
Distribution Revenue	**114,580**		
Reconciling Items			
Adjustment to distribution revenue		(1,312)	Due to use of normalized load and consumption for 2007 in rate model
		(5,478)	To remove deferred CDM revenue included in 2007 FS
		929	To remove Load transfers and Power Diversion included in 2007 FS
Retail Services Revenue		(313)	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		(594)	
Total Adjustments		**(6,768)**	
Total in 2009 EDR model		**107,812**	

Table 3 reconciles Other Revenue in the 2007 Audited Financial Statements and as presented in PowerStream's 2009 EDR application:

Table 3 –Other Revenue (2007)

Item	2007 FS, $000	2007 Rate Application $000	Notes
Other Revenue	**10,477**		
Reconciling Items			
Misc. Service revenues / rent from electric utility		(197)	Excluding non-distribution charges
Gain on Disposal of utility property		(4,433)	Excluding gain on sale of fibre assets
Revenue and expense from non-utility operations[5]		(1,120)	Defined as "Other revenue – unclassified" in USoA
Interest Income		1,762	Netted with interest expense in FS
Retail Services Revenue		313	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		594	
Total adjustments		**(3,081)**	
Total in 2009 EDR model		**7,022**	

[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 2007 Audited Financial Statements and as presented in PowerStream's 2009 EDR application:

Table 4 – OM&A (2007)

Item	2007 FS, $000	Adjustments in 2007 Rate Application $000	Notes
Total OM&A	**45,947**		
Reconciling Items			
Sponsorships		(183)	Sponsorships not recovered through distribution rates
A&G Expenses		(710)	Expenses related to M&A preparation - not recovered through distribution rates
Charitable contributions		(838)	Donations not recovered through distribution rates
Other Distribution Expenses		(1,544)	Ontario Capital Tax is removed, since it is calculated as part of PILs model
Non-distribution expenses		(6)	Excluded from EDR model
Total adjustments		**(3,281)**	
Total in 2009 EDR model		**42,665**	

The reconciliation of Amortization expenses as reported in the 2007 Audited Financial Statements and as provided in PowerStream's 2009 EDR application is presented in Table 5.

Table 5 – Amortization expense (2007)

Item	2007 Fin. Statements $000	Adjustments in 2007 Rate Application $000	Notes
Amortization expense	**29,666**		
Reconciling items			
		312	Amortization for SMART meters installed as of Dec. 31, 2007 and included in Rate Base [6]
		165	The amortization for Stranded assets /mechanical meters replaced by Smart meters[6]
		(249)	Adjustment to remove FMV of Aurora assets
		(10)	Amortization of non-distribution assets
Total Adjustments		**218**	
Total in 2009 EDR model[7]		**29,885**	

[6] Recorded in deferral accounts 1555 and 1556 in Financial Statements
[7] The slight difference is due to rounding in Financial Statements

A reconciliation of Capital Assets as reported in the 2007 Audited Financial Statements and as provided in PowerStream's 2009 EDR application is presented in the table below:

Table 6 – Capital Assets (2007)

Item	2007 Fin. Statements $000	Adjustments in 2007 Rate Application $000	2007 in Rate model $000	Notes
Gross Assets	**1,012,914**			
WIP		(39,844)		Excluded from Fixed Assets for Rate Base Calculation
Smart Meters		9,360		Smart Meters installed as of Dec. 2007 and included in Rate Base
Stranded Assets		8,285		Value of Stranded Assets added back
		(727)		Non-distribution items removed from Rate Base[8]
		123		Adjustment to remove FMV of Aurora assets
	Total Adjustments	**(22,803)**		
		Total Gross Assets in 2009 EDR model	**990,111**	
Contributed Capital	**(158,560)**			
	Total Adjustments	**(6,662)**		CC adjustment to remove FMV of Aurora assets
		Contributed Capital in 2009 EDR model	**165,222**	
Gross Assets Net of CC	**854,354**		**824,889**	

[8] Street Lighting and Sentinel lighting rental units

A reconciliation of Accumulated Amortization as reported in the 2007 Audited Financial Statements and as provided in PowerStream's 2009 EDR application is presented in the table below:

Table 7 – Accumulated Amortization (2007)

Item	2007 Fin. Statements $000	Adjustments in 2007 Rate Application $000	2007 in Rate model $000	Notes
Accumulated Amortization	**424,962**			
		36		Accumulated adjustment for FMV of Aurora's assets
Installed Smart Meters Amortization		312		Smart Meters installed as of Dec. 2007
Stranded Assets		3,819		Amortization add-back
Non-distribution assets		(226)		Non-distribution items removed from Rate Base[9]
Contributed capital		(533)		To remove FMV of Aurora's assets
Total Adjustments		**3,408**		
Total Amortization in 2009 EDR model			**428,370**	

[9] Street Lighting and Sentinel lighting rental units

3.0 BRIDGE YEAR (2008)

Table 1 compares PowerStream's 2008 Pro-forma Income Statement to information for the 2008 Bridge Year that is provided in this Application:

Table 1 – Reconciliation of Financial Statement to Rate Application

Statement of Income and Retained Earnings	2008 FS $000	Bridge Year $000	Table/Note
Revenues			
Sale of Energy	507,325	515,068	Financial Statements use original 2008 budget[10]
Distribution sales	113,681	110,899	*2*
Other revenue	6,288	7,398	*3*
	627,294	**633,365**	
Cost of Power Purchased	507,325	515,068	
Margin	**119,969**	**118,297**	
Operating Expenses	43,986	39,649	*4*
Earnings before amortization, interest and income taxes	75,983	78,647	
Amortization	32,206	33,046	*5*

[10] The original 2008 Sale of Energy / Cost of Power (COP) budget was lower than current forecast, since it was based on the lower energy prices. The reduction in forecasted load and decrease in transmission prices partially offset the impact of increased energy prices.

Table 2 reconciles Distribution Revenue in the 2008 Pro-Forma Income Statement and as presented in PowerStream's 2009 EDR application:

Table 2 –Distribution Revenue (2008)

Item	2008 FS, $000	2008 Rate Application $000	Notes
Distribution Revenue	**113,681**		
Reconciling Items			
Adjustment to distribution revenue		(982)	Pro forma FS include adjustment for unbilled revenue
		(1,000)	Pro forma FS include provision for deferred CDM revenue to be recognized
Rounding		10	
SSS Admin Charge Revenue		(810)	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets[11]
Total Adjustments		**(2,782)**	
Total in 2009 EDR model		**110,899**	

[11] The SSS admin charge in Financial Statements is as per original budget, slightly different from the updated forecast numbers used in the Rate Application

Table 3 reconciles Other Revenue in the 2008 Pro-Forma Income Statement and as presented in PowerStream's 2009 EDR application.

2008 Pro-Forma Financial Statements include the estimates made after the Rate Model was finalized in order to file the Application by the deadline.

Table 3 –Other Revenue (2008)

Item	2008 FS, $000	2008 Rate Application $000	Notes
Other Revenue	**6,288**		
Reconciling Items			
Misc. Service revenues / rent from electric utility		(258)	Excluding non-distribution charges (water billing)
		(231)	To exclude updates to the forecast that were made after Rate model was finalized
Revenue and expense from non-utility operations[12]		(1,100)	Defined as "Other revenue – unclassified" in USoA; refers to forecasted revenue from excess fibre
Interest Income		1,774	Netted with interest expense in FS
Retail Services Revenue		319	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		606	
Total adjustments		**1,110**	
Total in 2009 EDR model		**7,398**	

[12] 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 2008 Pro-Forma Income Statement and as presented in PowerStream's 2009 EDR application.

2008 Pro-Forma Financial Statements include the estimates made after the Rate Model was finalized in order to file the Application by the deadline.

Table 4 – OM&A (2008)

Item	2008 FS, $000	Adjustments in Rate Application, $000	Notes
Total OM&A	**43,986**		
Reconciling Items			
Updated Forecast Information			
A&G expenses		(2,091)	Net Increase in pro-forma FS, mainly due to: 1. Change in burden rates $1,050k 2. Bad debt write offs $955k
O&MA expenses		504	Net decrease in pro-forma FS, mainly due to: 1. forecasted decrease in asset management expenses $692K[13] 2. decreased forecasted metering cost $110k 3. partially offset by increased forecasted spending on cable locates $298k
Adjustments to remove non-distribution expenses:			
Sponsorships		(219)	Sponsorships not recovered through distribution rates
A&G Expenses		(650)	$650k Expenses related to M&A preparation - not recovered through distribution rates
Charitable contributions		(100)	Donations not recovered through distribution rates
Other Distribution Expenses		(1,780)	Ontario Capital Tax is removed, since it is calculated as part of PILs model
		(1)	Rounding in FS
Total adjustments		**(4,337)**	
Total in 2009 EDR model		**39,649**	

[13] Asset management cost decrease of $692k includes $375k for line and station maintenance, $130k for P&C, $100k for Control room software and other estimated cost decreases of $87k

The reconciliation of Amortization expenses as reported in the 2008 Pro-Forma Income Statement and as provided in PowerStream's 2009 EDR application is presented in Table 5.

Table 5 – Amortization expense (2008)

Item	2008 Fin. Statement $000	Adjustments in 2008 Rate Application $000	Notes
Amortization expense	**32,206**		
Reconciling items			
		624	Amortization for Smart meters installed as of Dec. 31, 2007 and included in Rate Base
		166	The Amortization for Stranded assets /mechanical meters replaced by Smart meters
		310	Calculation of Amortization in Pro-forma FS is done using "average" amortization rate, while Rate Application calculates amortization on a more detailed basis.
		(249)	Adjustment to remove FMV of Aurora assets
		(11)	Amortization of non-distribution assets
Total Adjustments		**840**	
Total in 2009 EDR model		**33,046**	

4.0 TEST YEAR (2009)

Table 1 reconciles PowerStream's 2009 Pro-forma Income Statement to information for the 2009 Test Year that is provided in this Application:

Table 1 – Reconciliation of Financial Statement to Rate Application

Statement of Income and Retained Earnings	2009 Income Statement, $000	2009 Test Year, $000	Tables
Revenues			
Sale of Energy	510,537	510,537	
Distribution sales	119,300	121,029	**2**
Other revenue	5,000	6,568	**3**
	634,837	**636,510**	
Cost of Power Purchased	510,537	510,537	
Margin	**124,300**	**127,597**	
Operating Expenses	47,200	45,098	**4**
Earnings before amortization, interest and income taxes	77,100	82,499	
Amortization	35,600	36,540	**5**

Table 2 reconciles Distribution Revenue in the 2009 Pro-Forma Income Statement and as presented in PowerStream's 2009 EDR application:

Table 2 –Distribution Revenue (2009)

Item	2009 FS, $000	2009 Rate Application $000	Notes
Distribution Revenue	**119,300**		
Reconciling Items			
Adjustment to distribution revenue		1,729	Pro-forma FS presents revenue for a calendar year, while Rate Application shows Rate year revenues
Total Adjustments		**1,729**	
Total in 2009 EDR model		**121,029**	

Table 3 reconciles Other Revenue in the 2009 Pro-Forma Income Statement and as presented in PowerStream's 2009 EDR application:

Table 3 –Other Revenue (2009)

Item	2009 FS, $000	2009 Rate Application $000	Notes
Other Revenue	**5,000**		
Reconciling Items			
Misc. Service revenues / rent from electric utility		(251)	Excluding non-distribution charges (water billing) of 251k, offset by the rounding difference in FS
Rounding in FS		40	
Interest Income		835	Netted with interest expense in FS
Retail Services Revenue		326	Included as Distribution Revenue in Financial Statements, but is part of Board Approved Revenue Offsets
SSS Admin Charge Revenue		618	
Total adjustments		**1,568**	
Total in 2009 EDR model		**6,568**	

Table 4 reconciles OM&A in the 2009 Pro-Forma Income Statement and as presented in PowerStream's 2009 EDR application:

Table 4 – OM&A (2009)

Item	2009 FS, $000	Adjustments in 2009 Rate Application $000	Notes
Total OM&A	**47,200**		
Reconciling Items			
Sponsorships		(219)	Sponsorships not recovered through distribution rates
A&G Expenses		(200)	Expenses related to M&A preparation - not recovered through distribution rates
Charitable contributions		(383)	Donations not recovered through distribution rates
Total adjustments		**(802)**	
Total in 2009 EDR model		**45,098**	

The reconciliation of Amortization expenses as reported in the 2009 Pro-Forma Income Statement and as provided in PowerStream's 2009 EDR application is presented in Table 5.

Table 5 – Amortization expense (2009)

Item	2009 FS $000	Adjustments in 2008 Rate Application $000	Notes
Amortization expense	**35,600**		
Reconciling items			
		312	Amortization for SMART meters installed as of Dec. 31, 2007
		166	The amortization for Stranded assets /mechanical meters replaced by Smart meters
		723	Calculation of Amortization in Pro-forma FS is done using "average" amortization rate, while Rate Application calculates amortization on a more detailed basis.
		(249)	Adjustment to remove FMV of Aurora assets
		(12)	Amortization of non-distribution assets
Total Adjustments		**940**	
Total in 2009 EDR model		**36,540**	

Schedule 21

RATING AGENCY REPORTS

Rating Report

Report Date:
November 16, 2007

Previous Report:
September 9, 2005

Electricity Distributors Finance Corporation

Analysts

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The Company

EDFIN was incorporated for the purpose of providing Ontario electric distributors with efficient access to the debt capital markets. EDFIN will purchase debentures and other evidences of indebtedness issued by LDCs and sell 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 three (formerly five) participating LDCs in EDFIN are PowerStream Inc., Enwin Utilities Ltd. (formerly Enwin Powerlines Ltd.), and Barrie Hydro Distribution Inc.

Recent Actions

September 1, 2005
Confirmed

Rating

Debt	Rating	Rating Action	Trend
Series 2002-1 Certificates	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating on the Series 2002-1 Certificates (Certificates) issued by Electricity Distributors Finance Corporation (EDFIN) at A (low) with a Stable trend. The rating is based on the lowest-rated of the three participants, Enwin Utilities Ltd (formerly Enwin Powerlines Ltd.), rated A (low).

The Certificates represent undivided co-ownership interests in unsecured debentures issued by the three participating local distribution companies (LDC Participants), namely PowerStream Inc. (PowerStream), Enwin Utilities Ltd. (Enwin) and Barrie Hydro Distribution Inc. (Barrie Hydro) to EDFIN. The obligations of the individual LDC Participants is 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.

DBRS has confirmed the rating of Enwin at A (low) with a Stable trend. Enwin continues to maintain a reasonable financial profile, reflecting its improving balance sheet and credit metrics. However, DBRS expects Enwin's heightened capital expenditure profile for the period 2007 to 2010 to create an external financing requirement. While the increased leverage is expected to affect Enwin's credit metrics, leverage is expected to be within 60%, thus enabling Enwin to maintain adequate metrics to support a rating of A (low). (Continued on page 2.)

Rating Considerations

Strengths

(1) Low business risk owing to predominantly regulated electricity distribution operations
(2) Solid balance sheets and reasonable credit metrics
(3) Strong franchise areas and favourable customer mix

Challenges

(1) Low regulatory returns
(2) Earnings are sensitive to the volume of electricity sold
(3) Refinancing risk
(4) Political risk and regulatory uncertainty

Financial Information

For 12 months ended June 30, 2007 (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.	100	481	56.0%	3.07	20.4%	A
Enwin Utilities Ltd.*	50	165	56.5%	2.08	15.8%	A (low)
Barrie Hydro Distribution Inc.	25	108	36.0%	4.49	31.1%	A

* Enwin figures are as of Dec 31, 2006

Rating Rationale (Continued from page 1.)

The rating of PowerStream has been confirmed at "A" with a Stable trend, as PowerStream continues to benefit from a strong and improved financial profile. However it expects leverage to increase marginally to 60% by 2008 due to the increased capital expenditures resulting from the construction of a new head office and the installation of Smart Meters. Given the Company's stated policy of maintaining leverage at 60%, in line with the Ontario Energy Board (OEB) approved deemed capital structure, DBRS expects the credit metrics to remain at a level appropriate for an "A" rating.

The rating of Barrie Hydro is confirmed at "A" with Stable trend, based largely on its solid and improved financial profile. Over the 2008 to 2011 period, Barrie Hydro expects to spend an average of $15 million annually on capital expenditures of which roughly 35% will be on servicing growth within its franchise area. DBRS expects this prolonged and heightened capital expenditure profile to create a fairly manageable external financing need without affecting the strong credit metrics in any significant way.

Overall, the three LDC Participants continue to benefit from a low level of business risk stemming from their regulated electricity distribution operations, solid financial profile and strong franchise areas with a favourable customer mix. The rating confirmation on the three LDC Participants is also supported by the improving regulatory outlook in Ontario. Over the next three years, the OEB will be re-basing the rates with full-cost-of-service proceedings for all distributors in Ontario. Barrie Hydro is in the first group to go through the re-basing of rates for the 2008 rate year, with the 3rd Generation Incentive Rate Mechanism applied in succeeding years, up to the 2010 rate year. The re-basing year for PowerStream and Enwin will be announced at a later date. The regulatory framework beyond 2010 remains uncertain, but DBRS expects the OEB will maintain a reasonable regulatory framework that should likely include cost of service recovery, a market-based rate of return and a performance-based incentive mechanism.

For the three LDC Participants, cash flows over the medium term will depend largely on the re-basing of rates, the 3rd Generation Incentive Rate Mechanism, and load growth with their respective service area.

Political intervention still remains a risk, especially in light of rising electricity commodity prices and anticipated increases in transmission and distribution rates over the medium- to longer-term.

Rating Considerations Details

Strengths

(1) Almost all earnings and cash flows are generated from the LDC Participants' low-risk, regulated distribution operations. The LDC Participants' exposure to higher-risk non-regulated businesses continues to remain limited.

(2) The LDC Participants continue to maintain solid balance sheets and reasonable credit metrics. These ratios are acceptable for their current rating categories given the low business risk for the LDC Participants stemming from their regulated electricity distribution operations.

(3) The franchise areas of all three LDC Participants have experienced population growth over the past five years. Further, the customer load profiles of the LDC Participants are reasonably well-diversified, consisting predominately of a residential and small commercial customer base. This provides a relatively stable and predictable demand load year over year, with limited influence from economic cycles.

Challenges

(1) The approved ROE of 9.0% for 2007 is low and has been in decline in recent years primarily due to the low-interest rate environment. Lower ROEs have a negative impact on earnings and cash flows.

(2) Earnings and cash flow for electricity-distribution companies are partially dependent on the volume of electricity sold and, hence, revenue earned from electricity sales. Seasonality, economic cyclicality and year-over-year changes in weather patterns directly impact the volume of electricity sold and revenue earned from electricity sales. In addition, economic growth impacts customer and load growth. However, the LDC Participants' generally favourable customer mix helps mitigate these risks.

(3) The three LDC Participants' long-term debt with EDFIN totalling $175 million matures on August 15, 2012. This bullet maturity poses a refinancing risk, although DBRS notes that the LDC Participants' credit profile, coupled with stable cash flows generated from strong franchise area with favourable customer mix, moderates this risk.

(4) Political risk and regulatory uncertainty is a challenge generally for LDCs in Ontario. The most significant risk in the near term is the possibility of political intervention, such as the imposition of rate caps with the passing of Bill 210 in December 2002, should the cost of electricity to end-consumers rise too quickly. Higher prices will arise from (a) costs associated with new generation capacity being added within the province; (b) higher distribution costs following a re-basing during the 2008 to 2010 period; and (c) the recovery of approximately $4 billion in transmission upgrades in the province during the next ten years. Should prices increase too quickly, there is a risk that the government would intervene in the rate-setting process. DBRS considers this risk to be reasonably low. Furthermore, there is regulatory uncertainty arising from the OEB's decision on December 20, 2006 concerning the Cost of Capital, and the 2nd Generation Incentive Regulation, which is effective only until 2010. The OEB has not yet provided details on the regulatory framework after 2010.

Structure

Issuer:	Electricity Distributors Finance Corporation
Amount:	$175.0 million
Term:	10 years through August 15, 2012
Interest Rate:	4.45%; 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.

Regulation

Regulatory Update

Electricity distribution operations in Ontario are regulated by the OEB under the Electricity Act, 1998 (the Electricity Act).

Currently, the LDCs operate under a performance-based incentive mechanism with a ROE of 9.0%, based on a forward looking cost-of-service for the mid-year rate decision. The OEB's deemed capital structure is 60%/40% for PowerStream and 55%/45% for Enwin and Barrie Hydro (the deemed capital structure is changing, see below).

The purchased power included in distribution rates is a flow through to consumers determined by the OEB based on a blend of fluctuating, fixed and capped prices paid to generators under the Regulated Price Plan (RPP). The RPP is based on a forecast of expected costs over the next 12 months. If the cost of supplying electricity differs from what was forecast, the OEB may re-adjust electricity prices accordingly in the next price period, in order to true up the RPP prices with the prices paid to generators.

On December 20, 2006, the OEB issued a 2007 rate adjustment model (2nd Generation Incentive Regulation Model) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. As a result, base distribution rates, exclusive of rate riders, will be adjusted formulaically to reflect an allowance for inflation subject to final determination by the OEB, and a fixed productivity offset of 1.0%. As such, no major financial impact for distributors, only a marginal increase in revenues is expected due to the inflation factor generally being slightly higher than the productivity factor.

The 2nd Generation Incentive Regulation will be in effect for the LDCs for a maximum of three years, until the 2010 rate year. In each of three subsequent years starting in 2008, one-third of the approximately 90 electricity distributors will have their distribution rates reviewed and reset by the OEB through a cost-of-service type of rate proceeding. LDCs rebased in 2008 will be subject to the 3rd Generation Incentive Rate Mechanism, applied in succeeding years up to the 2010 rate year. The two-thirds of LDCs that would not have gone through the re-basing process in 2008 will continue to have the 2nd Generation Incentive Regulation applied to their rates till they go the through the re-basing of rates in the following years, at which time the 3rd Generation Incentive Regulation will take effect. By 2010, all electricity distributors in Ontario would have undergone a re-basing of rates.

The OEB's December 20, 2006, decision also required that starting May 1, 2008, all distributors transition to a single deemed capital structure (60%/40%) over a three-year period. This will have no impact on PowerStream as its capital structure is already set at 60%/40%. However, Enwin and Barrie Hydro's regulated cash flow generation will be negatively affected by the decision, but the impact will be fairly modest.

The costs associated with the installation of Smart Meters is expected to be recovered through the imposition of a rate rider and the maintenance of a capital-variance account that will incorporate return-on-investment and amortization components, as well as an Operations Maintenance & Administration (OM&A) variance account that will reflect actual amounts spent plus carrying costs.

Rating

Debt	Rating	Rating Action	Trend
Series 2002-1 Certificates	A (low)	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Series 2002-1 Certificates	A (low)	A (low)	A (low)	A (low)	A (low)	A

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

The Company
Enwin Utilities Ltd. was created by the amalgamation of Enwin Powerlines Ltd., a regulated electricity distribution company, and Enwin Utilities Ltd., a management services company on January 1, 2007. The LDC serves approximately 85,000 customers in the Windsor service area. The newly amalgamated 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	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of Enwin Utilities Ltd. (formerly Enwin Powerlines Ltd.) at A (low) with a Stable trend. Enwin continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its reasonable financial profile and a strong record of cost containment.

On January 1, 2007, Enwin Powerlines Ltd., the regulated electricity distribution company, amalgamated with Enwin Utilities Ltd., the management services company, to create the new amalgamated entity, Enwin Utilities Ltd. (Enwin or the Company). Enwin Utilities Ltd. has assumed the EDFIN obligations. Given that the predecessor Enwin Utilities Ltd. did not have any debt on its balance sheet, the amalgamation should result in a slight improvement in the leverage of the amalgamated entity. Post-amalgamation, regulated activities are expected to comprise more than 90% of cash flows from operations.

Enwin continues to maintain a reasonable financial profile, reflecting its improving balance sheet and credit metrics. All credit metrics have improved from 2004 levels and continue to support the A (low) rating. The improved leverage is primarily attributable to positive free cash flows stemming from moderate dividend-payouts and relatively modest capital expenditures.

Enwin has significant exposure to large industrial customers, particularly the auto sector. Going forward, the downturn in the auto sector, especially the plant closure at Ford and many ancillary suppliers could pressure future cash flows. However, the Company anticipates that the relocation of some of the production from the closed Ford plant to other plants within Enwin's service area, the Windsor Casino expansion project and the opening of the Chrysler Paint Shop to somewhat mitigate the negative impacts. Enwin projects significantly heightened capital expenditures for 2007 to 2010, primarily due to the replacement of aging infrastructure, improving reliability and installation of Smart Meters. (Continued on page 6.)

Rating Considerations

Strengths
(1) Successful ongoing cost reduction program
(2) Expected efficiency improvement from amalgamation
(3) Strong financial profile

Challenges
(1) Managing the heightened capital expenditure profile
(2) Large exposure to industrial customers
(3) Low regulated returns
(4) Political and regulatory uncertainty

Financial Information

	For the year ended December 31				
	2006	2005	2004	2003	2002
EBIT interest coverage (times)	2.08	1.51	1.27	1.52	1.03
Total debt-to-capital	56.5%	63.0%	65.9%	64.5%	68.3%
Cash flow-to-total debt	15.8%	12.4%	9.7%	10.5%	5.7%
Operating cash flow ($ millions)	14.37	12.42	10.77	12.10	7.49
Net income before extras. ($ millions)	3.86	2.45	1.25	2.74	(0.23)
Operating margin	27.4%	21.2%	18.0%	23.0%	13.7%
Return on average equity	6.0%	4.2%	2.1%	4.4%	-0.4%
Electricity throughput (GWh)	3,128	3,339	3,173	3,235	3,386
Customer base	84,699	84,253	83,816	82,161	81,318

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Rating Rationale (Continued from page 5.)

DBRS expects the heightened capital expenditure profile combined with the amortizing promissory notes to create an external financing requirement of between $25 million to $30 million for the 2007 to 2010 period. While the increased leverage will affect the credit metrics of Enwin, the leverage is expected to be within 60%, thus enabling Enwin to maintain adequate credit metrics to sustain an A (low) rating. While cash flow from operations over the next two years will be primarily driven by population and load growth, cost savings as well as industrial demand, cash flows beyond 2008 will depend largely on the 2009 re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

Financial Profile and Outlook

	For the year ended December 31				
($ millions)	2006	2005	2004	2003	2002
EBITDA	21.41	17.66	16.03	17.84	13.07
EBIT	11.99	8.40	7.10	9.29	5.35
Interest Expense	5.76	5.57	5.57	6.13	5.17
Net income (before extras)	3.86	2.45	1.25	2.74	(0.23)
Depreciation	9.60	9.27	8.93	8.55	7.73
Other non-cash items	0.91	0.71	0.58	0.81	(0.01)
Cash Flow From Operations	14.37	12.42	10.77	12.10	7.49
Common dividends	(2.00)	(1.10)	-	-	-
Capex (net of capital contrib.)	(7.31)	(6.27)	(8.13)	(8.65)	(17.13)
Cash Flow Before Working Capital	5.05	5.06	2.64	3.45	(9.65)
Changes in working capital	(6.92)	2.47	(0.31)	(5.32)	(9.23)
Free Cash Flow	(1.87)	7.52	2.32	(1.87)	(18.88)
Adjusted for non-recurring non-cash	-	-	-	-	-
Share capital reduction	-	-	(1.10)	-	-
Other (investments)/dispositions	0.34	0.51	0.40	1.33	0.89
Settlement of regulatory assets/liabilities	2.51	-	-	-	
Increase in regulatory assets	(0.23)	5.59	4.13	1.57	(16.56)
Due to (from) related parties	7.87	(1.48)	-	-	
Net change in debt	(8.63)	(12.15)	(5.75)	(1.03)	34.54
Net Change in Cash	0.00	0.00	(0.00)	(0.00)	(0.00)

Key Financial Ratios	2006	2005	2004	2003	2002
Debt/capital	56.5%	63.0%	65.9%	64.5%	68.3%
EBITDA interest coverage	3.72	3.17	2.88	2.91	2.53
EBIT interest coverage	2.08	1.51	1.27	1.52	1.03
Cash flow-to-debt	15.8%	12.4%	9.7%	10.5%	5.7%
Return on Equity	6.0%	4.2%	2.1%	4.4%	-0.4%
Dividend payout	51.8%	44.9%	0.0%	0.0%	0.0%

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Summary

- Enwin continues to maintain a reasonable financial profile, reflecting its improving balance sheet and credit metrics. Leverage, cash flow-to-debt and interest coverage ratios have improved from 2004 levels and continue to support the current rating.

- In F2006, the Company posted significantly increased operating results primarily due to increased distribution rates and operating cost containment.

- Positive free cash flow stemming from moderate dividend-payouts and relatively modest capital expenditures have been largely responsible for the significantly improved debt-to-capital ratio of 53.0% from the 2003 levels.

- The large swings in working capital are mainly due to timing differences in when the Company pays for, and is paid for, power costs.

Outlook

- Post amalgamation, regulated activities are expected to comprise more than 90% of cash flow from operations.

- Enwin has exposure to large industrial customers (approximately 30% of total load) which are largely tied to the auto sector. Therefore the economic outlook for the manufacturing sector will impact earnings.

- Earnings and cash flow from operations are expected to come under pressure largely due to the downturn in the auto sector. However, some economic mitigants (i.e., the Casino Windsor expansion and the opening of the Chrysler Paint Shop) are expected.

- Cash flows beyond 2008 will depend largely on the re-basing of rates and the 3rd Generation Incentive Mechanism as well as economic conditions.

- Enwin projects significantly increased capital expenditures for 2007 to 2010 primarily due to the replacement of aging infrastructure, improving reliability and installation of Smart Meters. While Enwin projects a capital expenditure of approximately $12 million for F2007, almost twice what it spent in F2006, annual capital expenditures from 2008 to 2010 are expected to average roughly $18 million. Smart Meter installations will comprise about 35% of the capital expenditure profile during the 2008 to 2010 period.

- DBRS expects the heightened capital expenditures, combined with the amortizing promissory notes to create a total external financing requirement of between $25 million to $30 million for the 2007 to 2010 period. While the increased leverage will affect the credit metrics of Enwin, leverage is expected to be within 60%, thus enabling Enwin to maintain adequate credit metrics to sustain the A (low) rating.

Long-Term Debt and Bank Lines

Summary

Enwin's long-term debt currently consists of the following:

- Senior unsecured debentures totalling $50 million issued to the Electricity Distributors Finance Corporation, maturing August 15, 2012.
- Amortising subordinate debt from the City of Windsor (promissory notes) totalling $9.233 million.

Enwin currently has an unsecured committed $75 million revolving term facility which is renewed annually.

- As at August 1, 2007, the Company was no longer required to post prudential with the IESO.

Outlook

The Company's liquidity position is reasonably strong, reflecting the $75 million credit facilities and stable cash flow from operations.

Working capital requirements and any short- to medium-term needs would be funded with the Company's revolver.

Income Statement	For the year ended December 31				
	2006	2005	2004	2003	2002
Gross distribution revenues	224.76	253.41	218.77	221.28	257.15
Power purchases	183.84	216.83	182.45	183.60	222.21
Net distribution revenues	40.91	36.57	36.33	37.68	34.94
Ancillary revenues	2.79	2.94	3.08	2.71	3.99
Net operating revenues	43.70	39.52	39.41	40.39	38.93
Expenses:					
Operating and maintenance	22.29	21.86	23.38	22.55	7.14
Services provided by related parties	-	-	-	-	18.19
Administrative and other operating	-	-	-	-	0.73
Depreciation	9.42	9.27	8.93	8.55	7.73
Total operating expenses	31.71	31.12	32.31	31.10	33.79
Operating income	11.99	8.40	7.10	9.29	5.14
Interest income	-	-	-	-	0.20
Earnings before interest & taxes (EBIT)	11.99	8.40	7.10	9.29	5.35
Interest expense	5.76	5.57	5.57	6.13	5.17
Non-cash financial charges	-	-	-	-	-
Net financial expense	5.76	5.57	5.57	6.13	5.17
Pre-tax income	6.24	2.83	1.53	3.16	0.18
Income taxes	2.38	0.38	0.28	0.42	0.41
Income before extraordinary items	3.86	2.45	1.25	2.74	(0.23)
Extraordinary items	9.42	0.07	(6.01)	(0.23)	(0.32)
Net Income	13.28	2.52	(4.75)	2.51	(0.56)

Balance Sheet ($ millions)	As at December 31				As at December 31		
Assets	2006	2005	2004	Liabilities & Equity	2006	2005	2004
Cash & short-term investments	-	-	-	Short-term debt	34.7	40.6	48.9
A/R + unbilled revenue	35.9	35.2	33.0	A/P + accruals	19.9	27.7	24.3
Inventories	2.0	2.1	1.7	Other Current Liab.	4	3	0
Regulatory assets	-	-	4.9	**Current Liabilities**	58.2	70.8	73.2
Other	0.1	8.7	6.3	Customer deposits	0.5	0.8	1.0
Current Assets	38.0	46.1	45.8	Long-term debt	56.3	59.2	62.0
Net fixed assets	152.4	145.7	148.7	Other liabilities	13.4	12.5	12.0
Net investment in lease	-	8.6	9.0	Shareholders' equity	70.0	58.7	57.3
Other assets	8.0	1.7	1.9				
Total	198.4	202.0	205.4	**Total**	198.4	202.0	205.4

	For the year ended December 31				
Ratios/Operating Stats	2006	2005	2004	2003	2002
Operating margin	27.4%	21.2%	18.0%	23.0%	13.2%
Pre-tax margin (bef. extras.)	14.3%	7.2%	3.9%	7.8%	0.5%
Return on avg. common equity	6.0%	4.2%	2.1%	4.4%	-0.4%
MWh sold/employee	10,825	11,594	11,840	11,233	11,139
Customers/employee	293	293	313	285	267
Oper. costs (1) /avg. customer ($)	265	263	283	278	326
Rate base –- ($ millions)	165.4	165.4	161.3	161.3	161.3
Number of employees	289	288	268	288	304
Peak system demand (MW)	679	669	602	609	640
Electricity Throughputs					
Residential	683.5	740.0	675.0	684.0	666.8
General service	1,405.9	1,507.9	1,467.0	1,471.0	1,449.1
Large users	1,021.3	1,074.3	1,008.0	1,057.0	1,254.3
Street lighting	17.6	17.0	23.0	23.0	16.2
Total – (GWh)	3,128.3	3,339.2	3,173.0	3,235.0	3,386.3
Number of Customers					
Residential	76,407	75,921	75,107	73,512	72,501
General service	8,283	8,324	8,699	8,638	8,806
Large users	7	6	9	10	10
Street lighting	2	2	1	1	1
Total	84,699	84,253	83,816	82,161	81,318
Unit Revenues & Costs (cents per kWh throughputs)					
Average gross revenues	7.27	7.68	6.99	6.92	7.71
Power costs	5.88	6.49	5.75	5.68	6.56
Average net revenues	1.40	1.18	1.24	1.25	1.15
Variable costs (OM&A + PILS)	0.79	0.67	0.75	0.71	0.78
Fixed costs (deprec., int., gov't levies)	0.49	0.44	0.46	0.45	0.38
Total costs (excl. power costs)	1.27	1.11	1.20	1.16	1.16
Net margin	0.12	0.07	0.04	0.08	(0.01)

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

The Company
PowerStream Inc. was created in 2004 by the merger of three local distribution companies - Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc. and Richmond Hill Hydro Inc. PowerStream is 57% owned by the City of Vaughan and 43% by the Town of Markham. It is the fourth-largest electricity distribution company in Ontario, providing service to residential and business customers in the municipalities of Aurora, Markham, Richmond Hill and Vaughan. The Company serves approximately 232,000 customers in a service area of 640 square kilometers.

PowerStream Inc.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of PowerStream Inc. (PowerStream, or the Company) at "A" with a Stable trend. PowerStream continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its solid financial profile and a strong franchise area with a favourable customer mix.

The Company's financial metrics have steadily improved and continue to benefit from the growth in EBIT and earnings, which have trended upwards since the amalgamation in June 2004 (Hydro Vaughan, Markham Hydro and Richmond Hill Hydro). PowerStream had expected to achieve annual cost savings of $5 million to $7 million through synergies from the amalgamation, and reached this objective in both F2005 and F2006. Further, PowerStream's acquisition of Aurora Hydro in November 2005 has been earnings accretive and the Company has fully integrated Aurora Hydro into its operations, having completed all transitional issues pertaining to this acquisition. DBRS notes that PowerStream's management has been successful in steering the Company through the transitional challenges that were expected following the completion of the merger of three LDCs and the acquisition of Aurora Hydro within the last three years. PowerStream is expected to continue seeking additional growth opportunities through mergers/acquisitions. The Company currently has about 232,000 customers, and views a customer base in the 300,000-500,000 range to be optimal for a regulated distribution company. (Continued on page 12.)

Rating Considerations

Strengths

(1) Growth oriented franchise area: PowerStream expects a revenue growth of 2% to 4.6% over the next five years.
(2) Past experiences with merger, acquisition, and transition provide PowerStream with an advantage in future M&A transactions.
(3) Strong financial profile

Challenges

(1) Managing heightened capital expenditures
(2) Low regulated returns
(3) Political and regulatory uncertainty
(4) Identifying suitable M&A opportunities and managing transition.

Financial Information

	Unaudited 12 months ended Jun. 30, 2007	12 months ended Dec. 31, 2006	12 months ended Dec. 31, 2005	Jun. 1, 2004, to Dec. 31, 2004	12 months ended Dec. 31, 2003P	2002P
EBIT interest coverage (times)	3.07	2.90	2.27	2.10	3.08	2.97
Total debt-to-capital (1)	56.0%	56.4%	57.9%	59.7%	51.5%	54.0%
Cash flow-to-total debt (1)	20.4%	19.9%	17.5%	n/a	21.0%	19.1%
Operating cash flow ($ millions)	51.6	49.5	43.0	24.0	50.0	45.4
Net income ($ millions)	21.5	19.5	14.6	7.7	21.2	18.3
Operating margin	42.8%	40.6%	39.7%	n/a	45.5%	42.2%
Return on average equity	11.0%	10.5%	8.4%	n/a	9.9%	18.1%
Electricity throughput (GWh)	6,810	6,743	6,800	6,019	5,920	5,733
Customer base	232,230	228,518	219,816	197,167	190,250	181,071

P = pro forma (consolidation of Richmond Hill Hydro, Hydro Vaughan, and Markham Hydro).

n/a = not applicable. n.a. = not available.

(1) Includes subordinate debt (promissory notes to shareholders).

Rating Rationale (Continued from page 11.)

The Company posted a free cash flow deficit in F2006 primarily due to significantly heightened capital expenditures, with the deficit primarily funded with cash. The ongoing construction of a new head office, and transformer station expansion project contributed to the large swing in capital expenditures for F2006.

Prior to July 2007, PowerStream had four sets of rates in effect, one for each municipality it served. In July 2007, OEB approved PowerStream's application to harmonize its rates. The rate harmonization resulted in a modest rate increase of 0.1%.

The Company expects its leverage to increase to 60% by 2008 due to increased capital expenditures resulting from the construction of the new head office and the installation of Smart Meters. However, given the Company's stated policy of maintaining leverage at 60%, in line with the OEB approved deemed capital structure, DBRS expects the credit metrics will remain at a level appropriate for an "A" rating. While cash flow from operations over the next two years will be primarily driven by population and load growth as well as cost savings, cash flows beyond 2008 will depend largely on the 2009 re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

Financial Profile and Outlook

	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended
($ millions)	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005 (1)	Dec. 31, 2004	Dec. 31, 2003P
EBITDA	80.25	75.73	69.90	39.34	72.67
EBIT	51.6	47.2	43.8	24.5	48.7
Interest Expense	16.8	16.3	19.3	11.7	15.8
Net income (before extras)	21.5	19.5	14.6	7.7	21.2
Depreciation	30.2	30.0	27.6	15.8	27.7
Other non-cash items	(0.0)	(0.0)	0.9	0.5	1.0
Cash Flow From Operations	51.6	49.5	43.0	24.0	50.0
Common dividends	(4.7)	(6.6)	-	-	-
Capital expenditures	(55.1)	(57.8)	(26.0)	(14.7)	(21.6)
Cash Flow Before Working Capital	(8.3)	(14.9)	17.1	9.3	28.3
Changes in working capital	(6.7)	(20.2)	31.2	(18.7)	12.3
Free Cash Flow	(14.9)	(35.1)	48.2	(9.4)	40.6
Other (investments)/dispositions	4.6	9.6	7.8	0.9	(16.3)
Acquisition of Aurora Hydro	-	-	(30.0)	-	-
(Increase in)/recovery of regulatory assets	15.7	(0.8)	2.6	7.4	8.8
Net change in equity	-	-	6.8	-	-
Net change in debt	6.1	2.1	-	(25.0)	(3.0)
Other financing	0.9	(5.9)	(29.3)	1.6	(0.4)
Net Change in Cash	12.4	(30.0)	6.02	(24.4)	29.8
Key Financial Ratios					
Total debt-to-capital (2)	56.0%	56.4%	57.9%	59.7%	51.5%
EBITDA interest coverage	4.77	4.65	3.62	3.37	4.59
EBIT interest coverage	3.07	2.90	2.27	2.10	3.08
Cash flow-to-total debt (2)	20.4%	19.9%	17.5%	9.8%	21.0%
Return on Equity	11.0%	10.5%	8.4%	n/a	9.9%
Dividend payout	22.1%	33.6%	0.0%	0.0%	0.0%

P = pro forma (consolidation of Richmond Hill Hydro, Hydro Vaughan, and Markham Hydro).

(1) The F2005 financials include the financial results of Aurora Hydro for the 2 months period ending Dec. 31, 2005.

(2) Includes subordinate debt (promissory notes to shareholders).

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Summary

- PowerStream continues to maintain a strong financial profile, reflecting its solid balance sheet and credit metrics.

- Cash flow-to-debt and interest coverage ratios have improved from 2005 levels and continue to support the "A" rating.

- A moderate dividend-payout ratio is primarily responsible for the moderately improved debt-to-capital ratio of 56.0%. The Company expects to maintain a minimum dividend payout ratio of 50%, once a leverage of 60% is achieved.

- In F2006, the Company posted a free cash flow deficit primarily due to significantly heightened capital expenditures, funded primarily with cash. The capital budget that was not completed in F2005 was spent in F2006 along with the full F2006 capital budget. The capital expenditures for F2006 were focussed on head office construction, a transformer station expansion project, and a web-based system implementation. The large swings in working capital are mainly due to timing differences in when the Company pays for, and is paid for, power costs.

- Regulated operations account for almost all the cash flow from operations.

Outlook

- Cash flow from operations is expected to increase moderately, along with earnings in 2007 due to the modest rate increase approved by the OEB and the customer growth within the service area.

- While growth in cash flow from operations over the next two years will be primarily driven by population and load growth, cash flows beyond 2008 will depend largely on the re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

- PowerStream projects significantly increased capital expenditures for 2007 and 2008, primarily due to the continued construction of its head office, and the installation of Smart Meters. In order to fund its increased capital expenditure program, it expects its leverage to increase to 60% by 2008. Additional debt of approximately $16 million ($8 million in both 2007 and 2008) is expected to be incurred due to the deferral of interest payments on the Notes Payable to the shareholders, which would be added to the principal balance.
  - The OEB has approved some initial funding for the installation of Smart Meters. The remainder of the costs associated with the installations is expected to be recovered through future rate riders.
  - Given the Company's stated financial policy of maintaining leverage at 60% in line with the OEB approved deemed capital structure, DBRS expects the credit metrics to remain at a level appropriate to support the "A" rating.

Long-Term Debt and Bank Lines

Summary

PowerStream's long-term debt currently consists of the following:

- Senior unsecured debentures totalling $100 million issued to the Electricity Distributors Finance Corporation, maturing August 15, 2012.
- Subordinate debt to shareholders (promissory notes) totalling $146.1 million.
  - $78.2 million held by the City of Vaughan; and
  - $67.9 million held by the Town of Markham.

The two promissory notes are repayable 90 days following demand by the City or the Town, no earlier than January 1, 2008. These notes have been classified as long term by PowerStream as it is not the intent of the City or the Town to demand repayment within the next year.

- The interest on these promissory notes was deferred for eight quarters commencing October 1, 2006 for five years.

PowerStream currently has access to the following unsecured bank-credit facility:

- $125 million revolving demand facility for a term of 5 years, renewable annually.

As at December 31, 2006, the Company had utilized $22 million to provide the IESO with a letter of credit for prudential support.

Outlook

The Company's liquidity position is strong, reflecting the fairly modest utilization of the credit facility, stable cash flow from operations, zero short-term obligations, and a reasonable cash position.

Working capital requirements and any short- to medium-term needs would be funded with the Company's operating line.

Income Statement	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended
($ thousands)	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003P
Gross electricity revenues	595.7	581.2	592.2	289.6	484.8
Power purchases	486.1	475.7	491.3	235.7	377.7
Net distribution revenues	109.6	105.5	100.9	53.9	107.1
Ancillary revenues	10.8	10.7	9.3	7.0	-
Contribution from Richmond Hill Hydro Inc.	-	-	-	-	-
Net operating revenues	120.4	116.2	110.2	61.0	107.1
Expenses					
Operating and maintenance	16.9	16.1	15.9	6.7	12.5
General and administration	21.2	22.3	22.3	13.6	19.6
Municipal and property taxes	2.1	2.1	2.1	1.3	2.3
Depreciation & amortization	28.7	28.5	26.1	14.9	24.0
Total operating expenses	68.9	69.0	66.4	36.5	58.4
Operating income	51.6	47.2	43.8	24.5	48.7
Other (income)/expense	-	-	-	-	-
Earnings before interest & taxes (EBIT)	51.6	47.2	43.8	24.5	48.7
Interest expense	16.8	16.3	19.3	11.7	15.8
Non-cash financial charges	-	-	-	-	-
Net interest expense	16.8	16.3	19.3	11.7	15.8
Pre-tax income	34.7	30.9	24.5	12.8	32.9
Income taxes/PILS	13.3	11.5	9.9	5.1	11.7
Net income	21.5	19.5	14.6	7.7	21.2

Electricity Distributors Finance Corporation

Report Date:
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Balance Sheet	Unaudited				Unaudited		
($ millions)	As at Jun. 30	As at December 31			As at Jun. 30	As at December 31	
Assets	2007	2006	2005	**Liabilities & Equity**	2007	2006	2005
Cash & short-term investments	18.5	4.5	41.7	Short-term debt	-	-	-
A/R & unbilled revenue	110.1	114.5	99.8	A/P & accruals	98.5	100.3	111.8
Inventories	7.4	5.4	5.8	Other	3.7	2.4	3.0
Other	0.9	0.6	0.5	**Current Liabilities**	102.3	102.6	114.9
Current Assets	136.9	124.9	147.8	Customer deposits	11.6	12.7	13.4
Net fixed assets	414.1	404.8	376.8	Long-term debt	252.2	248.2	246.1
Regulatory assets	-	-	-	Regulatory liabilities	24.3	14.6	15.3
Other assets	14.6	16.0	17.6	Other liabilities	9.9	8.5	6.2
Goodwill & other assets	33.0	33.0	33.0	Shareholders' equity	198.3	192.2	179.3
Total	598.5	578.7	575.2	**Total**	598.5	578.7	575.2

	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended
Ratios/Operating Stats	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003P
Operating margin	42.8%	40.6%	39.7%	40.1%	45.5%
Pre-tax margin	28.9%	26.6%	22.2%	21.0%	30.7%
Return on avg. common equity	11.0%	10.5%	8.4%	4.0%	9.9%
MWh sold/employee	18,405	19,102	19,597	15,966	n.a.
Customers/employee	628	647	633	523	n.a.
Oper. costs/avg. customer ($)	165	171	183	105	n.a.
Rate base	481	468	443	417	417.0
Number of employees	370	353	347	377	n.a.
Peak system demand (MW)	1,577	1,577	1,485	1,240	n.a.
Electricity Throughputs					
Total – (GWh)	6,810	6,743	6,800	6,019	5,920
Number of Customers					
Residential	203,909	200,794	192,706	172,636	166,230
General service	28,268	27,671	27,075	24,500	23,989
Large users	4	6	7	5	5
Street lighting	49	47	28	26	26
Total	232,230	228,518	219,816	197,167	190,250
Unit Revenues & Costs (cents per kWh throughputs)					
Average gross revenues	8.91	8.78	8.85	4.93	8.19
Power costs	7.14	7.05	7.23	3.92	6.38
Average net revenues	1.77	1.72	1.62	1.01	1.81
Variable costs (OM&A + PILS)	0.75	0.74	0.71	0.42	0.74
Fixed costs (deprec., int., gov't levies)	0.70	0.70	0.70	0.46	0.71
Total costs (excl. power costs)	1.45	1.43	1.41	0.88	1.45
Net margin	0.32	0.29	0.21	0.13	0.36

P = pro forma (consolidation of Richmond Hill Hydro, Hydro Vaughan, and Markham Hydro).
n.a. = not available.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Issuer Rating	A	A	A	A (low)	N/R	N/R

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

The Company
Barrie Hydro Distribution Inc. is a regulated electricity distribution company with approximately 68,000 customers in the municipalities of Barrie, Bradford West Gwillimbury, New Tecumseth, Penetanguishene and Thornton. It is wholly-owned by Barrie Hydro Holdings Inc. which in turn is owned by the City of Barrie. Barrie Hydro Holdings Inc. also wholly owns a non-regulated energy services company; Barrie Hydro Energy Services Inc. Barrie Hydro Distribution Inc. comprises more than 95% of assets and revenues of Barrie Hydro Holdings Inc.

Barrie Hydro Distribution Inc.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of Barrie Hydro Distribution Inc. (Barrie Hydro or the Company) at “A” with a Stable trend. Barrie Hydro continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its strong financial profile and a growth oriented franchise area with a favourable customer mix.

The Company’s financial metrics have steadily improved and continue to benefit from the growth in EBIT and earnings, which have trended upwards since F2004 largely due to both distribution rate increases and population growth. While debt levels have remained stable since F2003, leverage has decreased primarily due to retained earnings growth stemming from historically modest dividend payments.

In F2006, the Company undertook a number of capital projects focussed on both improving reliability and servicing growth that resulted in significantly increased capital expenditures. This resulted in a fairly modest free cash flow deficit that was funded with cash balances. (Continued on page 17.)

Rating Considerations

Strengths

(1) Growth oriented franchise area: the city of Barrie’s population grew by almost 20% over the past five years. Future population growth is expected to be robust.
(2) Significantly lower leverage relative to peers provides for financial flexibility.
(3) Strong financial profile

Challenges

(1) Managing the heightened capital expenditures.
(2) Low regulated returns
(3) Refinancing risk
(4) Political and regulatory uncertainty

Financial Information

	Unaudited 12 months ended Jun 30, 2007	For the year ended December 31 2006	2005	2004	2003
EBIT interest coverage (times)	4.49	4.08	3.95	3.48	3.26
Total debt-to-capital	36.0%	37.9%	38.8%	40.0%	40.4%
Cash flow-to-total debt	31.1%	27.6%	27.5%	23.5%	27.7%
Operating cash flow ($ millions)	14.0	13.1	13.2	11.3	12.9
Net income before extras. ($ millions)	5.1	4.5	5.8	4.3	6.5
Operating margin	43.3%	40.5%	44.8%	39.8%	39.2%
Return on average equity	6.5%	5.8%	7.8%	6.1%	9.9%
Electricity throughput (GWh)	1,590	1,560	1,564	1,474	1,419
Customer base	67,416	67,211	65,800	63,973	61,597

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Rating Rationale (Continued from page 16.)

Over the 2008 to 2011 period, Barrie Hydro expects to spend an average of $15 million annually to maintain reliability and service growth. Roughly 35% of the capital expenditure during this period is expected to be spent on growth related projects while Smart Meter installations are expected to account for 20% of the total capital budget. DBRS expects this prolonged and heightened capital expenditure profile to create a very modest external financing need without affecting the strong credit metrics in any significant way.
Barrie Hydro's promissory notes held by the City of Barrie in the amount of $20 million mature on December 31, 2007. The Company expects the notes to be either extended by the City or refinanced with an external long-term facility. Given Barrie Hydro's strong financial profile, DBRS does not expect any refinancing issues.

Barrie Hydro is in the first group to go through the re-basing of rates for the 2008 rate year, with the 3rd Generation Incentive Rate Mechanism applied in succeeding years, up to the 2010 rate year. Hence, cash flow from operations in the medium term will largely hinge on the re-basing proceedings as well as population and load growth in its service territory. However, the Company's regulated electricity distribution operations, together with its strong growth oriented franchise area with favourable customer mix, is expected to provide a reasonable degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

Financial Profile and Outlook

($ millions)	Unaudited 12 months ended Jun 30, 2007	For the year ended December 31 2006	2005	2004	2003
EBITDA	23.35	21.59	21.28	18.36	17.49
EBIT	14.61	13.16	14.03	11.45	11.14
Interest Expense	3.25	3.23	3.56	3.29	3.41
Net income (before extras)	5.08	4.49	5.78	4.26	6.51
Depreciation	8.74	8.43	7.25	6.91	6.35
Other non-cash items	0.18	0.17	0.22	0.11	0.08
Cash Flow From Operations	14.01	13.09	13.25	11.28	12.94
Common dividends	(2.09)	(3.10)	(1.28)	(1.10)	-
Capital expenditures	(15.17)	(12.16)	(7.47)	(13.40)	(9.97)
Cash Flow Before Working Capital	(3.25)	(2.17)	4.50	(3.21)	2.97
Changes in working capital	0.18	(8.57)	3.58	2.03	3.82
Free Cash Flow	(3.06)	(10.75)	8.08	(1.18)	6.79
Other (investments)/dispositions	2.94	0.16	0.57	(0.20)	0.05
Customer deposits	1.59	0.34	(1.86)	0.87	1.41
(Increase in)/recovery of regulatory assets	3.56	3.52	1.31	1.72	(1.14)
Deferrred charges	(0.31)	(0.31)	-	(0.48)	
Net change in equity	-	-	-	-	-
Net change in debt	-	-	-	-	(0.15)
Net Change in Cash	4.71	(7.04)	8.09	0.74	6.96
Key Financial Ratios					
Total debt-to-capital	36.0%	37.9%	38.8%	40.0%	40.4%
EBITDA interest coverage	7.18	6.69	5.98	5.59	5.13
EBIT interest coverage	4.49	4.08	3.95	3.48	3.26
Cash flow-to-total debt	31.1%	27.6%	27.5%	23.5%	27.7%
Return on Equity	6.5%	5.8%	7.8%	6.1%	9.9%
Dividend payout	41.0%	69.1%	22.1%	25.8%	0.0%

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Summary

- Barrie Hydro continues to maintain a strong financial profile, reflecting its solid balance sheet and credit metrics. Cash flow-to-debt and interest coverage ratios have improved from 2003 levels and continue to support the current rating. While debt levels have remained stable since 2003, leverage decreased primarily due to historically modest dividend payments, the exception being F2006 where the company paid $3.1 million in dividends.

- The modest free cash flow deficit (before working capital) in F2006 was largely due to increased capital expenditure. The Company undertook a number of projects to both improve reliability and service growth within its service area. The deficit was primarily funded with cash.

- The low ROE levels are reflective of the low actual leverage Barrie Hydro carries, compared to the 55% approved by OEB, resulting in an under-earning on a portion of invested equity. While Barrie Hydro continues to maintain very strong credit metrics for the current rating, it is limited by its modest size of asset and rate base, and limited access to the capital markets.

Outlook

- Cash flow from operations, along with earnings is expected to experience modest growth in F2007 largely due to customer growth. Over the past four years, the customer base grew by an average 3.2% annually.

- Given that Barrie Hydro is to go through re-basing for the 2008 rate year, earnings and cash flow from operations beyond 2008 will largely depend on the outcome of the re-basing proceedings as well as customer base growth. Over the 2008 to 2011 period, Barrie Hydro expects to spend an average of $15 million annually to maintain reliability, prepare for growth and install Smart Meters. Growth related capital expenditure is expected to account for roughly one-third of the total spending while Smart Meter installation will account for 20% during the 2008 to 2011 period.

- The heightened future capital expenditure profile is expected to create a small external financing need, which would marginally impact credit metrics.
  - Along with external financing, the ratios will weaken marginally, but DBRS expects the credit metrics to stay well within the “A” rating.

Long-Term Debt and Bank Lines

Summary

Barrie Hydro’s long-term debt consists of the following:

- Senior unsecured debentures totalling $25 million issued to the Electricity Distributors Finance Corporation, maturing August 15, 2012.
- Subordinate debt to the City of Barrie (promissory notes) totalling $20 million maturing on December 31, 2007. This debt has not been classified as short-term as it is expected to be renewed or refinanced through another long-term debt facility. The City of Barrie renewed this debt in January 1, 2006.

Barrie Hydro currently has a $10 million unsecured bank line, which was fully available as at June 30, 2007.

Outlook

The Company’s liquidity position is strong, reflecting the fully available credit facility, stable cash flow from operations, zero short-term obligations and a significant cash position.

Working capital requirements and any short- to medium-term needs would be funded with the Company’s operating line.

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Income Statement	Unaudited 12 months ended	For the year ended December 31			
($ millions)	Jun 30, 2007	2006	2005	2004	2003
Gross distribution revenues	142.46	138.78	146.84	123.21	104.11
Power purchases	112.30	110.24	119.06	97.78	78.62
Net distribution revenues	30.16	28.54	27.78	25.42	25.49
Ancillary revenues	3.59	3.95	3.55	3.34	2.90
Net operating revenues	33.75	32.48	31.33	28.77	28.39
Expenses					
Operating and maintenance	3.32	3.80	3.37	4.10	4.69
General and administration	7.08	7.08	6.69	6.30	6.22
Municipal and property taxes	-	-	-	-	-
Depreciation & amortization	8.74	8.43	7.25	6.91	6.35
Total operating expenses	19.15	19.32	17.30	17.32	17.25
Operating income	14.61	13.16	14.03	11.45	11.14
Other (income)/expense	-	-	-	-	-
Earnings before interest & taxes (EBIT)	14.61	13.16	14.03	11.45	11.14
Interest expense	3.25	3.23	3.56	3.29	3.41
Non-cash financial charges	-	-	-	-	-
Other financial (income)/expense	-	-	-	-	-
Net interest expense	3.25	3.23	3.56	3.29	3.41
Pre-tax income	11.36	9.94	10.48	8.16	7.73
Income taxes/PILS	6.27	5.45	4.70	3.90	1.21
Income before extraordinary items	5.08	4.49	5.78	4.26	6.51
Extraordinary items	-	-	-	-	-
Net Income	5.08	4.49	5.78	4.26	6.51

Balance Sheet	Unaudited				Unaudited		
($ millions)	As at	As at Dec. 31			As at	As at Dec. 31	
Assets	Jun. 30, 2007	2006	2005	**Liabilities & Equity**	Jun. 30, 2007	2006	2005
Cash & short-term. investments	7.7	2.2	9.2	Short-term debt	-	-	-
A/R & unbilled revenue	25.1	25.2	23.6	A/P + accruals	23.6	17.7	23.4
Inventories	2.9	1.6	1.2	Customer deposits	20.2	4.3	4.9
Goodwill and other assets	0.6	0.7	0.4	**Current Liabilities**	43.9	22.0	28.4
Current Assets	36.3	29.7	34.4	Customer deposits	2.6	2.6	2.4
Net fixed assets	128.5	124.7	119.2	Long-term debt	45.0	45.0	45.0
Regulatory assets	-	-	1.9	Regulatory & Other liabilities	3.8	17.9	14.3
Other assets	10.5	10.7	10.6	Shareholders' equity	80.0	77.6	76.0
Total	175.3	165.1	166.1	**Total**	175.3	165.1	166.1

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Ratios/Operating Stats	Unaudited 12 months ended Jun. 30, 2007	For the year ended December 31 2006	2005	2004	2003
Operating margin	43.3%	40.5%	44.8%	39.8%	39.2%
Pre-tax margin (bef. extras.)	15.1%	13.8%	18.4%	14.8%	22.9%
Return on avg. common equity	6.5%	5.8%	7.8%	6.1%	9.9%
MWh sold/employee	14,324	13,688	13,485	12,706	12,556
Customers/employee	607	590	567	551	545
Oper. costs /avg. customer ($)	155	164	155	166	180
Rate base – ($ millions)	108	108	108	108	108
Number of employees	111	114	116	116	113
Peak system demand (MW)	341.9	313.0	304.0	274.9	283.8
Electricity Throughputs					
Total – (GWh)	1,590.0	1,560.4	1,564.3	1,473.9	1,418.8
Number of Customers					
Residential	60,830	60,659	59,174	57,473	55,195
General service	6,579	6,545	6,619	6,493	6,395
Large users	-	-	-	-	-
Street lighting	7	7	7	7	7
Total	67,416	67,211	65,800	63,973	61,597
Unit Revenues & Costs (cents per kWh throughputs)					
Average gross distribution revenues	9.19	9.15	9.61	8.59	7.54
Power costs	7.06	7.07	7.61	6.63	5.54
Average net distribution revenues	2.12	2.08	2.00	1.95	2.00
Variable costs (OM&A + PILS)	1.05	1.05	0.94	0.97	0.85
Fixed costs (deprec., int., gov't levies)	0.75	0.75	0.69	0.69	0.69
Total costs (excl power costs)	1.80	1.79	1.63	1.66	1.54
Net margin	0.32	0.29	0.37	0.29	0.46

n.a.=not available

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Issuer Rating	A	A	A	A	A	A

Note:
All figures are in Canadian dollars unless otherwise noted.

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June 3, 2008

Research Update:

Electricity Distributors Finance Corp. Debt Rating Raised to 'A' On Sector Stability

Primary Credit Analyst:
Nicole Martin, Toronto (1) 416-507-2560;nicole_martin@standardandpoors.com

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Research Update:

Electricity Distributors Finance Corp. Debt Rating Raised to 'A' On Sector Stability

Rationale

On June 3, 2008, Standard & Poor's Ratings Services raised its unsecured debt rating on Toronto-based Electricity Distributors Finance Corp. (EDFIN) to 'A' from 'A-'. The rating action reflects the influence of energy policy stability and regulatory consistency in Ontario on the underlying credit quality of each of the three companies supporting the EDFIN debentures. (For more details on the credit-positive trends influencing the sector, please see "Key Contributors To Rating Actions On Ontario Electricity Distributors," to be published on RatingsDirect following this research update.)

EDFIN is a special-purpose corporation that acts as a financial conduit for participating local distribution companies (LDCs) in the Province of Ontario (AA/Stable/A-1+). EDFIN itself has no assets or liabilities. The rating on EDFIN's C$175 million, 6.45% unsecured debentures series 2002-1 outstanding reflects the risk profile of the least creditworthy participant. 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 any of the other participants. Three utility holding companies service the EDFIN debt obligation: Barrie Hydro Distribution Inc. (C$25 million), EnWin Utilities Ltd. (C$50 million), and PowerStream Inc. (C$100 million). The debt matures Aug. 15, 2012.

All three LDCs enjoy an excellent business risk profile supported by stable, regulated cash flows from a monopoly franchise. Offsetting these strengths are intermediate financial risk profiles of varying strength. Although the debt rating necessarily reflects the risk profile of the least creditworthy participant, the differences between the three do not affect the rating outcome. This has not always been the case, and the situation could change. Some participants are exploring mergers with, or acquisitions of, other Ontario LDCs. A largely debt-financed transaction or change in financial policy by one of the three companies could affect the debt rating.

Cash flow to service the EDFIN debt comes almost entirely from regulated electricity distribution activities and is stable and predictable. The Ontario Energy Board's regulatory framework supports the LDC's cash flow stability. The framework allows for the recovery of prudent costs and the opportunity to earn a modest return. Regulatory cost recovery is generally predictable and timeliness is improving. The current environment limits the LDC's exposure to commodity risk. Although the LDC must bill electricity customers for the commodity delivered, the cost is a flow through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements. Net distribution revenues are subject to modest volumetric risk due to weather. There is no near-term expectation of energy policy or electricity market framework initiatives that would affect the regulatory environment or LDC credit quality.

Each LDC's monopoly position in its service franchise and the asset-intensive and essential nature of electricity distribution limit competitive risk. The electricity distribution business also carries relatively low operating risk, and all three participants exhibit average operational efficiency and reliability.

The intermediate financial risk profiles of all EDFIN participants are relatively stable. Nevertheless, balance-sheet and cash-flow strength vary among the participants, largely due to differing financial policies. Barrie Hydro and EnWin Utilities retain much stronger balance sheets than PowerStream. Standard & Poor's believes the weakest adjusted funds from operations (AFFO) interest coverage ratio in the group could achieve 3.0x in 2008. We project AFFO-to-average total debt to exceed 15% in the same period. Interest and debt coverages vary among the participants. By 2009, the regulator will have phased in a deemed capital structure of 60% debt and 40% equity for all LDCs, which will have a negative-but-manageable impact on cash flow for EnWin Utilities and Barrie Hydro Distribution. For these two, the regulator previously used a deemed 45% common equity component in the capital structure for tariff-setting purposes. Powerstream's actual capital structure is aligned with its regulatory deemed equity layer of 40%.

Ratings List

Electricity Distributors Finance Corp.

Ratings Raised And Outlook Removed

	To	From
Senior unsecured debt	A	A-/Positive

Complete ratings information is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; select your preferred country or region, then Ratings in the left navigation bar, followed by Credit Ratings Search.

Schedule 22

2007 TAX RETURN

F-N/A-C

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs 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 services office or tax centre. 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 the *T2 Corporation – Income Tax Guide* (T4012).

055 **Do not use this area**

Identification

Business Number (BN) 001 85750 3346 RC0002

Corporation's name
002 POWERSTREAM INC.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes 2 No X

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** 004 1 Yes 2 No

Address of head office
Has this address changed since the last time you filed your T2 return? 010 1 Yes X 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 you filed your T2 return? 020 1 Yes X 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 you filed your T2 return? 030 1 Yes X 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 X 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 2007-01-01 YYYY MM DD
Tax year-end 061 2007-12-31 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 X

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 subsection 249(3.1)? 066 1 Yes 2 No X

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes 2 No X

Is this the first year of filing after:
Incorporation? 070 1 Yes 2 No X
Amalgamation? 071 1 Yes 2 No X
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 X
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes 2 No X

Is this the final return up to dissolution? 078 1 Yes 2 No X

Is the corporation a resident of Canada?
080 1 Yes X 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 X
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
091 100 092 093 094 095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		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
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	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	X	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	X	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	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	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	X	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) is the corporation claiming the refundable portion of Part I tax?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	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
Was 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	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
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

Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
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	X	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	X	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

* We do not print this schedule.

Additional information

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? (Only complete if **yes** was entered at line 281) 282

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

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 X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X

Taxable income

	Line	Amount	Total	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		35,400,459	A
Deduct: Charitable donations from Schedule 2	311	106,170		
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		106,170	106,170	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			35,294,289	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		35,294,289	
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)			35,294,289	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** 33,235,180 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . **405** 35,294,289 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year 365 = ... ______ 1

400,000 x Number of days in the tax year after 2006 365 / Number of days in the tax year 365 = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . **410** 400,000 C

Notes:

1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 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 400,000 x **415** *** 1,120,677 D / 11,250 = ... 39,846,293 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 Number of days in the tax year before January 1, 2008 365 / Number of days in the tax year 365 x 16 % = ______ 5

Amount A, B, C, or F whichever is the least ______ x Number of days in the tax year after December 31, 2007 and before January 1, 2009 ______ / Number of days in the tax year 365 x 17 % = ______ 6

Amount A, B, C, or F whichever is the least ______ x Number of days in the tax year after December 31, 2008 ______ / Number of days in the tax year 365 x 17 % = ______ 7

Total of amounts 5, 6, and 7 – enter on line 9 **430** ______ G

* 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.

** 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 the previous tax years, the amount to be entered at 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 at 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.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . **435** ______ H

Amount H ______ x Number of days in the tax year in 2005 ______ / Number of days in the tax year 365 x 3 % = ______ I

Amount H ______ x Number of days in the tax year in 2006 ______ / Number of days in the tax year 365 x 5 % = ______ J

Amount H ______ x Number of days in the tax year in 2007 365 / Number of days in the tax year 365 x 7 % = ______ K

Resource deduction – total of amounts I, J and K
Enter amount L on line 10. . . . . **438** ______ L

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			35,294,289	A
Amount Z1 from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Taxable resource income from line 435		D		
Amount used to calculate the credit union deduction (from Schedule 17)		E		
Amount from line 400, 405, 410, or 425, whichever is the least		F		
Aggregate investment income from line 440	2,165,279	G		
Total of amounts B, C, D, E, F, and G	2,165,279	▶	2,165,279	H
Amount A minus amount H (if negative, enter "0")			33,129,010	I

Amount I	33,129,010 x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	2,319,031	J
Amount I	33,129,010 x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=		K
Amount I	33,129,010 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 %	=		K1
Amount I	33,129,010 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	x	10 %	=		K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2
Enter amount L on line 638. ..... 2,319,031 L

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)				M
Amount Z1 from Part 9 of Schedule 27		N		
Amount QQ from Part 13 of Schedule 27		O		
Taxable resource income from line 435		P		
Amount used to calculate the credit union deduction (from Schedule 17)		Q		
Total of amounts N, O, P, and Q		▶		R
Amount M minus amount R (if negative, enter "0")				S

Amount S	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=		T
Amount S	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=		U
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 %	=		U1
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	x	10 %	=		U2

General tax reduction – total of amounts T, U, U1, and U2
Enter amount V on line 639. V

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	440	2,165,279 × 26 2 / 3 % =		577,408 A
Foreign non-business income tax credit from line 632				
Deduct:				
Foreign investment income (from Schedule 7)	445	× 9 1 / 3 % =		
		(if negative, enter "0")	▶	B
Amount A minus amount B (if negative, enter "0")				577,408 C
Taxable income from line 360			35,294,289	
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least				
Foreign non-business income tax credit from line 632		× 25 / 9 =		
Foreign business income tax credit from line 636		× 3 =		
		▶	35,294,289	
			× 26 2 / 3 % =	9,411,810 D
Part I tax payable minus investment tax credit refund (line 700 minus line 780)			7,810,382	
Deduct: Corporate surtax from line 600			395,296	
Net amount			7,415,086 ▶	7,415,086 E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450			577,408 F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460	113,837	
Deduct: Dividend refund for the previous tax year	465	113,837	
		▶	G
Add the total of:			
Refundable portion of Part I tax from line 450 above		577,408	
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		
		577,408 ▶	577,408 H
Refundable dividend tax on hand at the end of the tax year – Amount G plus amount H	485		577,408

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 of Schedule 3	4,736,400 × 1 / 3	1,578,800 I
Refundable dividend tax on hand at the end of the tax year from line 485 above		577,408 J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)		577,408

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 %	550	13,411,830	A

Corporate surtax calculation

Base amount from line A above	13,411,830	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	3,529,429	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6	3,529,429	7
Net amount (line 1 **minus** line 7)	9,882,401	8

Corporate surtax*

Line 8 9,882,401 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year = 365 / 365 x 4 % = **600** 395,296 B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31	602		C

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		2,165,279	i
Taxable income from line 360	35,294,289		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	35,294,289 ▶	35,294,289	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604	144,352	D
Subtotal (**add** lines A, B, C, and D)		13,951,478	E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	3,529,429	
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		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount L	638	2,319,031	
General tax reduction from amount V	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644	558	
Federal political contributions 646 1,000			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	292,078	
Subtotal		6,141,096 ▶ 6,141,096	F

Part I tax payable – Line E **minus** line F Enter amount G on line 700.	7,810,382	G

Summary of tax and credits

Federal tax

Part I tax payable	700	7,810,382
Part I.3 tax payable from Schedule 33, 34, or 35	704	
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		7,810,382

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		7,810,382 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784	577,408	
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	7,232,974	
Total credits	890	7,810,382	7,810,382 B

Refund code 894 Overpayment

Balance (line A minus line B)

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

Enclosed payment 898

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 X

Certification

I, 950 LOMBARDI (Last name in block letters) 951 LUCY (First name in block letters) 954 DIRECTOR, 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 further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-06-26 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes 2 No X

958 GERI YIN Name in block letters 959 (905) 532-4635 Telephone number

Language of correspondence – Langue de correspondance

990 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.

1 English / Anglais X 2 Français / French

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
	INSTALMENT	14,166,257
	TRANSFER TO CT23	-6,933,283
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	7,232,974 A
	Total instalments credited to the taxation year per T9	7,232,974 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

Form identifier 100

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	142,582,000	124,903,000
	Total tangible capital assets	2008	+	854,354,000	952,723,000
	Total accumulated amortization of tangible capital assets	2009	–	424,962,000	423,145,000
	Total intangible capital assets	2178	+	34,418,000	
	Total accumulated amortization of intangible capital assets	2179	–	1,428,000	
	Total long-term assets	2589	+	11,681,000	
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	616,645,000	654,481,000
	Liabilities				
	Total current liabilities	3139	+	119,681,000	
	Total long-term liabilities	3450	+	287,812,000	
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	407,493,000	
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	209,152,000	183,239,000
	Total liabilities and shareholder equity	3640	=	616,645,000	183,239,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	45,395,000	19,482,000

* Generic item

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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	2007-12-31

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	+	604,357,000	581,162,000
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	604,357,000	581,162,000
	Cost of sales	8518	+		
	Total operating expenses	9367	+	579,586,000	560,949,000
	Total expenses (mandatory field)	9368	=	579,586,000	560,949,000
	Total revenue (mandatory field)	8299	+	614,834,000	591,896,000
	Total expenses (mandatory field)	9368	–	579,586,000	560,949,000
	Net non-farming income	9369	=	35,248,000	30,947,000
	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	=	35,248,000	30,947,000
	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	–	14,100,000	11,465,000
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	21,148,000	19,482,000

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? .... **095** 1 Yes [X] 2 No [ ]

Is the accounting practitioner connected* with the corporation? .... **097** 1 Yes [ ] 2 No [X]

* 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 accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report .... 1 [X]

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** above, answer the following question:

Has the accounting practitioner expressed a reservation? .... **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

Were notes to the financial statements prepared? .... **101** 1 Yes [X] 2 No [ ]

If *Yes*, complete lines 102 to 107 below:

Are any values presented at other than cost? .... **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? .... **103** 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? .... **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? .... **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? .... **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? .... **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? .... **108** 1 Yes [X] 2 No [ ]

If *Yes*, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? .... **109** 1 Yes [ ] 2 No [X]

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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	2007-12-31

- 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*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

	Line	Amount	Total
Net income (loss) after taxes and extraordinary items per financial statements			21,148,000 A
Add:			
Provision for income taxes – current	101	14,100,000	
Interest and penalties on taxes	103	217,503	
Amortization of tangible assets	104	30,779,069	
Amortization of intangible assets	106	222,000	
Recapture of capital cost allowance from Schedule 8	107	289,632	
Income or loss for tax purposes – joint ventures or partnerships	109	-33,166	
Charitable donations and gifts from Schedule 2	112	106,170	
Taxable capital gains from Schedule 6	113	2,165,279	
Political donations	114	1,000	
Scientific research expenditures deducted per financial statements	118	1,088,481	
Non-deductible club dues and fees	120	39,202	
Non-deductible meals and entertainment expenses	121	71,141	
Non-deductible automobile expenses	122	6,831	
Reserves from financial statements – balance at the end of the year	126	11,505,165	
Subtotal of additions		60,558,307 ▶	60,558,307
Other additions:			
Debt issue expense	208	545,000	
Miscellaneous other additions:			
600 ADDBACK RE: 12(1)(x)	290	9,763,594	
601 CAPITAL TAX BOOKED FOR ACCOUNTING	291	1,544,000	
602 INTEREST INCOME ON TAX	292	29,010	
603.1 Additions to building constructed — 312,083			
603.2 Ontario Specified Tax Credits — 87,916			
Total — 399,999	293	399,999	
Subtotal of other additions	199	12,281,603 ▶	12,281,603
Total additions	500	72,839,910 ▶	72,839,910
Deduct:			
Gain on disposal of assets per financial statements	401	4,492,935	
Capital cost allowance from Schedule 8	403	31,797,456	
Cumulative eligible capital deduction from Schedule 10	405	694,549	
Scientific research expenses claimed in year from Form T661	411	779,520	
Reserves from financial statements – balance at the beginning of the year	414	8,175,149	
Subtotal of deductions		45,939,609 ▶	45,939,609
Other deductions:			
Miscellaneous other deductions:			
701 S.13(7.4) ELECTION	391	9,763,594	
702 CAPITAL TAX PER CT 23	392	1,490,840	
704.1 INTEREST CAPITALIZED FOR ACCOUNTING — 1,393,408			
Total — 1,393,408	394	1,393,408	
Subtotal of other deductions	499	12,647,842 ▶	12,647,842
Total deductions	510	58,587,451 ▶	58,587,451
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			35,400,459

* For reference purposes only

T2 SCH 1 E (08)

Canada

Attached Schedule with Total

Line 603 – Amount

Title Line 603 – Amount

Description	Amount
Interest on deferred intrst pmnts, deduct'd for actg, capitalized for tax	285,556 47
Property tax expensed on building being constructed	26,527 00
Total	312,083 47

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

- 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)
VARIOUS	106,170
Subtotal	106,170
Add: Total donations of less than $100 each	
Total donations in current tax year	106,170

		Federal	Quebec	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	106,170		
Subtotal (line 250 **plus** line 210)		106,170	106,170	106,170
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		106,170 A	106,170	106,170
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	106,170	106,170	106,170
Charitable donations closing balance	280			

Amounts carried forward – Charitable donations

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2004			
6th prior year *	2003			
Total (to line A)				

* These donations expired in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %		26,550,344	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)		26,550,344	J
Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less)		106,170	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

	Line	Federal	Quebec	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			

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2004			
6th prior year *	2003			
Total				

* These donations expired in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal	Quebec	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			

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2004			
6th prior year *	2003			
Total				

* These donations expired in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Quebec		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 × (B / C) = Additional deduction for gifts of medicine for the current year **610** ______

Quebec

A ______ × (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ × (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	Quebec	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	Quebec	Alberta
1st prior year	2006			
2nd prior year	2005			
3rd prior year	2005			
4th prior year	2004			
5th prior year	2004			
6th prior year *	2003			
Total				

* These donations expired in the current year.

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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	2007-12-31

- 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 for purposes of 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 taxation 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*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible to a 45% gross up for the purpose of the dividend tax credit for individuals.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (Use only one line per corporation, abreviating its name if necessary)	A	B	C Business Number	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD	E Non-taxable dividend under section 83
			Complete if payer corporation is connected			
	200		205	210	220	230
1						
					Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation 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)	F1	F2	G Total taxable dividends paid by connected payer corporation	H Dividend refund of the connected payer corporation	I Part IV tax before deductions F x 1 / 3 *
				If payer corporation is not connected, leave these columns blank.		
	240			250	260	270
1						
Total (enter amount of column F on line 320 of the T2 return)						

J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

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 taxation year for purposes of a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	D Taxable dividends paid to connected corporations 430
1	VAUGHAN HOLDINGS INC.		2007-12-31	2,699,748
2	MARKHAM ENTERPRISES CORPORATION		2007-12-31	2,036,652
3				

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 4,736,400

Total taxable dividends paid in the taxation year to other than connected corporations	450	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	4,736,400

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above)	460	4,736,400
Other dividends paid in the taxation year (total of 510 to 540)		
Total dividends paid in the taxation year	500	4,736,400
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 taxation year for purposes of a dividend refund		4,736,400

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss, or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act*, if the control of the corporation has been acquired by a person or group of persons.

For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes [ ] 2 No [X] If *Yes*, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

	No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 less cols. 130 and 140) 150	Foreign source
1									
				Totals					

Total adjustment under subsection 112(3) of the ITA to all losses identified in Part 1 160

Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) . . . . A

Part 2 – Real estate – Do not include losses on depreciable property

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 less cols. 230 and 240) 250	Foreign source
1							
		Totals					B

Part 3 – Bonds

	Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 less cols. 330 and 340) 350	Foreign source
1									
				Totals					C

Part 4 – Other properties – Do not include losses on depreciable property

	Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 less cols. 430 and 440) 450	Foreign source
1	FIbre property sale		7,708,722	3,206,907	171,258	4,330,557	
2							
		Totals	7,708,722	3,206,907	171,258	4,330,557	D

Part 5 – Personal-use property (Do not include listed personal property)

	Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 less cols. 530 and 540) 550	Foreign source
1							
	Note: Losses are not deductible	Totals					E

Part 6 – Listed personal property

	Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 less cols. 630 and 640) 650	Foreign source
1							
		Totals					

Note: Net listed personal property losses may only be applied against listed personal property gains

Subtract: Unapplied listed personal property losses from other years 655

Amount from line 655 is from line 530 in Part 5 of Schedule 4

Net gains (or losses) F

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

	Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	(Loss)(column 920 less cols. 930 and 940) 950	Foreign source
1								
			Totals					G

Note: Properties listed in Part 7 should not be included in any other parts of Schedule 6

Allowable business investment losses . . . . Amount G x 50 % = H

Enter amount H on line 406 of Schedule 1

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss)		4,330,557	I
Add:			Foreign source
Capital gains dividend received in the year	875		J
Capital gains reserve opening balance (from Schedule 13)	880		K
Subtotal (**add** amounts I, J, and K)		4,330,557	L
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		M
Capital gains or losses (amount L minus amount M)	890	4,330,557	

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above)				4,330,557	N
Deduct the following gains that are included in the amount N:					
Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the *Income Tax Act*					
realized prior to May 2, 2006		x 50 % =		O	Foreign source ☐
realized after May 1, 2006				P	Foreign source ☐
	Subtotal: O plus P **895**				
Gain on donation of ecologically sensitive land					
realized prior to May 2, 2006		x 50 % =		Q	Foreign source ☐
realized after May 1, 2006				R	Foreign source ☐
	Subtotal: Q plus R **896**				
Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) as proposed in federal Bill C-50				R-2	Foreign source ☐
Total: line 895 plus line 896 plus R-2					S
Amount N minus amount S				4,330,557	T
Total capital losses: If amount T is a loss, enter it on line 210 of Schedule 4					
Taxable capital gains: If amount T is a gain, enter it on this line and multiply	4,330,557	x 50 % =		2,165,279	U
Enter amount U on line 113 of Schedule 1					

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SCHEDULE 7

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part 1 Tax" in the *T2 Corporation – Income Tax Guide.*

Part 1 and Part 2 – Aggregate and foreign investment income calculation

	Canadian investment income	Foreign investment income	Aggregate investment income	
Eligible portion of taxable capital gains included in the income for the year before taking into account the capital gains reserve (federal) of Schedule 13	2,165,279	001	002 2,165,279	A1
Reserve's eligible portion (addition/deduction)				A2
Eligible portion of taxable capital gains included in the income for the year after taking into account the capital gains reserve (federal) of Schedule 13 (total of amounts A1 and A2)	2,165,279		2,165,279	A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009	012	B
Net capital losses of other years claimed on line 332 on the T2 return			022	C
Total of amounts B and C				D
Amount A **minus** amount D (if negative, enter "0")	2,165,279		2,165,279	E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)				
Taxable dividends				
Other property income				
Total income from property		019	032	F
Exempt income		029	042	G
Amounts received from NISA Fund No. 2 (AGRI) that were included in computing the corporation's income for the year			052	H
Taxable dividends deductible (total of Column F on Schedule 3)		049	062	I
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		059	072	J
Total of amounts G, H, I, and J				K
Amount F **minus** amount K				L
Total of amount E **plus** amount L	2,165,279		2,165,279	M
Total losses from property (in box 82 include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)		069	082	N
Amount M **minus** amount N (if negative, enter "0")	2,165,279	079 L	092 O 2,165,279	

Note: The aggregate investment income is the aggregate world source income.

Enter amount L, foreign investment income, on line 445 of the T2 return.
Enter amount O, aggregate investment income, on line 440 of the T2 return.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A Partnership name 200	B Total income (loss) of partnership from an active business 300	C Corporation's share of amount in column B 310

D Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] 315	E Corporation's income (loss) of the partnership (column C **plus** column D) 320	F Number of days in the partnership's fiscal period 325	G Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** 330	H Column E **minus** column G (if negative, enter "0")	I Lesser of columns E and G (if column E is negative, enter "0") 340
Total	350		Total	385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount . . . . **370** ____

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) . . . . **380** ____

Total of lines 370 and 380 . . . . ____ ► ____ J

Amount at line 385 or line J, whichever is less . . . . **390** ____

Specified partnership income (line 360 **plus** line 390) . . . . **400** ____

* Use one of the following business limits to calculate column G, whichever applies:

- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 above (if the net amount is negative, enter "0" on line O) . . . . ____ K

Add: Specified partnership loss (from line 380 above) . . . . ____ L

Subtotal ____ M

Deduct: Specified partnership income (from line 400 above) . . . . ____ N

Partnership income (enter on line S below) . . . . **450** ____ O

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return				35,400,459	P
Deduct: Foreign business income after deducting related expenses*	500				
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**		2,165,279			
Net property income = amount F **minus** amount G, H, and N* (page 1)			Q		
Personal services business income after deducting related expenses*	520				
		2,165,279	▶	2,165,279	
		Net amount		33,235,180	R
Deduct: Partnership income (line 450 above)					S
Income from active business carried on in Canada (enter on line 400 of the T2 return – if negative, enter "0")				33,235,180	T

* If negative, **add** instead of **subtracting**.
**This amount may only be negative to the extent of any allowable business investment losses.

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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	2007-12-31

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 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 (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		351,736,287		-928,922	1,327,297		349,480,068	4	0	0	13,979,203	335,500,865
2	2		78,555,032			0		78,555,032	6	0	0	4,713,302	73,841,730
3	8		16,225,677	13,609,655		52,202	6,778,727	23,004,403	20	0	0	4,600,881	25,182,249
4	10		3,453,028	2,291,179		35,903	1,127,638	4,580,666	30	0	0	1,374,200	4,334,104
5	12		1,121,332	2,834,680		0	1,417,340	2,538,672	100	0	0	2,538,672	1,417,340
6	17		712,182			0		712,182	8	0	0	56,975	655,207
7	42		548,453			838,085		-289,632	12	289,632	0		
8		WORK-IN-PROGRESS	29,443,645	10,712,754		0	5,356,377	34,800,022	0	0	0		40,156,399
9	13	HYDRO VAUGHAN	264,569			0		264,569	N/A	0	0	105,329	159,240
10	13	RICHMOND HILL	2,733			0		2,733	N/A	0	0	2,733	
11	13	MARKHAM HYDRO	450,350			0		450,350	N/A	0	0	83,187	367,163
12	45		1,511,208	1,407,088		0	703,544	2,214,752	45	0	0	996,638	1,921,658
13	13	PS Inc - 2005 Additioin	149,827			0		149,827	N/A	0	0	43,854	105,973
14	13		74,239	9,855		0	4,928	79,166	N/A	0	0	18,662	65,432
15	47		21,205,086	40,726,856		1,041,525	19,842,666	41,047,751	8	0	0	3,283,820	57,606,597
		Total	505,453,648	71,592,067	-928,922	3,295,012	35,231,220	537,590,561		289,632		31,797,456	541,313,957

* 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*.

**** 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.

T2 SCH 8 (06)

Canada

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		71,582,212	
Additions for tax purposes – Schedule 8 leasehold improvements	+	9,855	
Operating leases capitalized for book purposes	+		
Capital gain deferred	+		
Recapture deferred	+		
Deductible expenses capitalized for book purposes – Schedule 1	+		
See attached	+	4,002,764	
Total additions per books	=	75,594,831 ▶	75,594,831
Proceeds up to original cost – Schedule 8 regular classes		3,295,012	
Proceeds up to original cost – Schedule 8 leasehold improvements	+		
Proceeds in excess of original cost – capital gain	+	4,330,557	
Recapture deferred – as above	+		
Capital gain deferred – as above	+		
Pre V-day appreciation	+		
See attached	+	17,470,522	
Total proceeds per books	=	25,096,091 ▶	– 25,096,091
Depreciation and amortization per accounts – Schedule 1	–		30,779,069
Loss on disposal of fixed assets per accounts	–		
Gain on disposal of fixed assets per accounts	+		4,492,935
Net change per tax return	=		24,212,606

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		422,068,393
Opening net book value	–	397,855,372
Net change per financial statements	=	24,213,021

If the amounts from the tax return and the financial statements differ, explain why below.

Difference = $415 Immaterial

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount (Schedule 8Rec)

Description	Amount
Capitalized interest deducted for tax purposes	1,237,865 00
Adds to Process reengineering deducted on schedule 1	179,300 00
Adjustments to NBV of fiber optics disposed of	2,553,849 00
Diff in cost fiber sale (tax vs acctg): 3,206,907 - 3,175,157 = 31,750	31,750 00
Total	4,002,764 00

Attached Schedule with Total

Tax return – Other – Amount

Title Tax return – Other – Amount - S8Rec

Description	Amount
Adjustments to NBV of residential meters disposed of	4,606,488 00
Cost of smart meter additions not included in NBV of fixed assets	9,360,493 00
Proceeds allocated to inventory and legal fees	2,262,536 00
Adjustments to NBV of fixed assets	928,922 00
Interest and property tax on buildings in construction included in WIP	312,083 00
Total	17,470,522 00

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

- 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	9,922,135 A
Add: Cost of eligible capital property acquired during the taxation year	222			
Other adjustments	226			
Subtotal (line 222 plus line 226)		x 3 / 4 =	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")			▶	D
Amount transferred on amalgamation or wind-up of subsidiary			224	E
Subtotal (add amounts A, D, and E)			230	9,922,135 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) (if amount K is negative, enter "0" at line M and proceed to Part 2)				9,922,135 K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249	
amount K	9,922,135			
less amount from line 249				
Current year deduction	9,922,135	x 7.00 % =	250	694,549 *
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			694,549 ▶	694,549 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	9,227,586 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.

T2 SCH 10 (04)

Canada

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 amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	EMPLOYEE FUTURE BENEFITS	6,321,654		918,910		7,240,564
2	ALLOWANCE FOR DOUBTFUL A	850,000				850,000
3	INVENTORY PROVISION	300,000				300,000
4	HOLDBACKS PAYABLE	703,495		1,161,106		1,864,601
5	Reserves in accruals			490,000		490,000
6	Donation accrual			760,000		760,000
7						
	Reserves from Part 2 of Schedule 13					
	Totals	8,175,149		3,330,016		11,505,165

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.

Canada Revenue Agency / Agence du revenu du Canada

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. References to parts, sections, and subsections on this schedule are from 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 for credits earned in tax years that end after 1997 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
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);
   - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Claim for Scientific Research and Experimental Development (SR&ED) Carried out in Canada*;
   - 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, *Scientific Research and Experimental Development Expenditures;* Information Circular 86-4, *Scientific Research and Experimental Development;* Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program;* and Guide T4088, *Claiming Scientific Research and Experimental Development – Guide to Form T661.*

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. Qualified 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 ITCs 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. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures made after February 22, 2005, 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. For SR&ED expenditures made before February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

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) throughout the tax year, 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 throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures:	
• in 2004	7 %
• after 2004	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	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 [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its business limit for that previous 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 the total of their business limits for that last year.

Note: A CCPC calculating a refundable ITC for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). For tax years ending after March 22, 2004, the association rule remains the same 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 [X]

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	Description of investment	Date available for use	Location used (province)	Amount of investment
105	110	115	120	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

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

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).

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures (including contributions to agricultural organizations for SR&ED)*	350	1,460,392
Capital expenditures	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	1,460,392

* 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 throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). This also applies for tax years ending after March 22, 2004, 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 395 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).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) . . . **390** 31,384,069

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return) . . . **395** ______

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations:

Calculation of the $2,000,000 SR&ED expenditure limit . . . $ **5,000,000** *

Subtract: line 390 from Part 9 or $400,000*, whichever is more . . . 31,384,069 x 10 = 313,840,690

Excess (if negative, enter "0") . . . ______ F

Line F ______ x Line 395 / Line 4 on page 4 of the T2 return 400,000 = ______ G1

Line G1 ______ x Number of days before February 26, 2008 365 / Number of days in the tax year 365 = ______ G2

Calculation of the $3,000,000 SR&ED expenditure limit . . . $ **7,000,000**

Subtract: line 390 from Part 9 or $400,000, whichever is more* . . . 31,384,069 x 10 = 313,840,690

Excess (if negative, enter "0") . . . ______ G3

Line G3 ______ x 40,000,000 – (Taxable capital used in Canada for previous tax year 508,078,825 – 10,000,000) / 40,000,000 = ______ G4

Line G4 ______ x Number of days after February 25, 2008 / Number of days in the tax year 365 = ______ G5

SR&ED expenditure limit – Add lines G2 and G5) . . . ______ **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 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** ______

* If your tax year immediately follows a tax year that ended before 2007, the references to $6,000,000 and $400,000 should be $5,000,000 and $300,000 respectively.

** Amount G or H cannot be more than $3,000,000 ($2,000,000 for a tax year that ended before February 26, 2008).

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	1,460,392	x	20 % =	292,078	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 % =	
470		x	30 % =	
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) 292,078

* For corporations that are not CCPCs throughout the year, 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	292,078		
Credit allocated from a partnership	550			
	Subtotal	292,078	▶	292,078
Total credit available				292,078
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560	292,078		
Credit carried back to the previous year(s) (from Part 13)			P	
Credit transferred to offset Part VII tax liability	580			
	Subtotal	292,078	▶	292,078
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	

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

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)		

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

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)			
Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.		______	Z

* 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)			
Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.		______	HH

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, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- 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
1.			

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**

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

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 on page 5. 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
Enter amount OO at line A1 in Part 29. . . . . . ______ OO

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 and after 2002.

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 and after 2002, 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 and after 2002 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 and after 2002:

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")			WW
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) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

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, Part 18, incurred in 2003 **865** x 5 % = ZZ

Expenditures from line YY, Part 18, incurred in 2004 **867** x 7 % = AAA

Expenditures from line YY, Part 18, incurred after 2004 **870** x 10 % = BBB

Total current-year credit (add amounts ZZ, AAA, and BBB) **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**

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

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. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages **or** $2,000.

	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**
1.					
				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

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	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)		

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not 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.				

*CCA: capital cost allowance

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		

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 after March 18, 2007, 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	2006-12-31	Credit to be applied	941	
2nd previous tax year	2005-12-31	Credit to be applied	942	
3rd previous tax year	2005-10-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

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)) .... 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 on page 13. 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 on page 8		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 Enter amount A3 on line 602 on page 7 of the T2 return.		A3

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)	292,078	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) Enter amount B6 at line 652 on page 7 of the T2 return.	292,078	B6

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99

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)
	292,078	292,078			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
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				
1991-05-31				
1990-05-31				
1989-05-31				*
Total				

B+C+D+G **Total ITC utilized** 292,078

* 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 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	VAUGHAN HOLDINGS INC.				57.000	
2	MARKHAM ENTERPRISES CORPORATION				43.000	
3						
4						
5						
6						
7						
8						
9						
10						

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
POWERSTREAM INC.	85750 3346 RC0002	2007-12-31

On: 2007-12-31

- 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 [X] 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? . . . . . [X] Yes [ ] No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . [X] Yes [ ] No
5. Corporations that become a CCPC or a DIC . . . . . [ ] Yes [X] 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 [X] 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 [X] 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)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")			**050**	A
GRIP at the end of the previous tax year			**100**	37,159,280 B
Taxable income for the year (DICs enter "0")*		**110**	35,294,289 C	
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**	2,165,279		
Subtotal (add lines 120, 130, and 140)		2,165,279 ▶	2,165,279 D	
Income taxable at the general corporate rate (line C minus line D)		**150**	33,129,010	
After-tax income (line 150 multiplied by 68 %)			**190**	22,527,727 E
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)			▶	F
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**	G
Subtotal (add lines A or B (as applicable), E, F, and G)				59,687,007 H
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)			▶	I
GRIP before adjustment for specified future tax consequences (line H minus line I) (amount can be negative)			**490**	59,687,007
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)			**560**	
GRIP at the end of the year (line 490 minus line 560) Enter this amount on line 160 on Schedule 55.			**590**	59,687,007

*** Note:** 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.

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 of page 1 or leave it blank.

First previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year		31,384,069 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)	310,910 M1		
Subtotal (add lines K1, L1, and M1)	310,910 ▶	310,910 O1	
Subtotal (line J1 minus line O1) (if negative, enter "0")		31,073,159 ▶	31,073,159 P1

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 . . . . ________ Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ________ S1

Aggregate investment income (line 440 of the T2 return) . . . . ________ T1

Subtotal (**add** lines R1,S1, and T1) ________ ▶ ________ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ________ ▶ ________ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") ________ X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 **multiplied by** 68 %) . . . **500** ________

Second previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year 1,861,125 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

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ________ N2

Subtotal (**add** lines K2, L2, M2, and N2) ________ ▶ ________ O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") 1,861,125 ▶ 1,861,125 P2

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 . . . . ________ Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ________ R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ________ S2

Aggregate investment income (line 440 of the T2 return) . . . . ________ T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ________ U2

Subtotal (**add** lines R2, S2, T2, and U2) ________ ▶ ________ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ________ ▶ ________ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") ________ X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 **multiplied by** 68 %) **520** ________

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2005-10-31

Taxable income before specified future tax consequences from the current tax year 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) M3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N3

Subtotal (**add** lines K3, L3, M3, and N3) ▶ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") ▶ P3

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 Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S3

Aggregate investment income (line 440 of the T2 return) T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U3

Subtotal (**add** lines R3, S3, T3, and U3) ▶ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") ▶ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) ... **540**

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") .... Y

Enter amount Y on line 560.

***Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or 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 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 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 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 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 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 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.

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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	2007-12-31

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. 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 Calculation (LRIP)*; 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 *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		4,736,400		
Total taxable dividends paid in the tax year	100	4,736,400		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	59,687,007
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190	

Enter the amount from line 190 at 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 (line A of Schedule 54)				B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290	

Enter the amount from line 290 at line 710 of the T2 return.

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CLAIM FOR SCIENTIFIC RESEARCH AND EXPERIMENTAL DEVELOPMENT (SR&ED) CARRIED OUT IN CANADA

Prepared without audit from information supplied by the taxpayer.

- Use this form to claim SR&ED carried out in Canada during the year. File it with your return of income.
- If you are filing a T2 corporation return of income, place this form on top of the return so that we can identify your SR&ED claim quickly.
- Use a separate form to support SR&ED expenditures incurred by each partnership of which you are a partner.
- Use Guide T4088, *Claiming Scientific Research and Experimental Development Expenditures*, to help you fill out this form. You can also consult our Web site at **www.cra.gc.ca/sred/** for an online help guide.
- If the SR&ED was performed in the province of Newfoundland and Labrador, Nova Scotia, New Brunswick, Québec, Ontario, Manitoba, Saskatchewan, or British Columbia, or in the Yukon Territory, you may be entitled to a provincial or territorial tax credit.
- Complete schedules A, B, C, D, E and F, if they apply to your situation.
- Prepare and retain schedules to support the breakdown for each expenditure claimed in this form and on the required attachments.
- On this form, references to the Act are to the *Income Tax Act*. References to the Regulations are to the *Income Tax Regulations*.
- All the information requested in this form including the attachments, schedules and any other document supporting your expenditures is prescribed information. You have to file the information that applies to your claim, along with Schedule T2SCH31 or Form T2038(IND), within 12 months of the filing-due date of your return of income for the year you incurred the expenditures. If you do not meet this reporting deadline, we may reject your claim.

Part 1 – General Information

Name of claimant
POWERSTREAM INC.

Claimant's business address and postal code
161 Cityview Blvd
VAUGHAN L4H 0A9

Claimant's Web site (if available)
http://www.

Business Number, social insurance number, or partnership identification number
85750 3346 RC0002

Return for tax year from: 2007-01-01 to: 2007-12-31 (Year Month Day)

100 Name of contact person
GERI YIN

105 Telephone number/extension
(905) 532-4635

110 Fax number

142 Is the claim filed for a partnership? 1 Yes 2 No X

145 If yes, what is the name of the partnership?

130 Is this the first time you are claiming for SR&ED? 1 Yes X 2 No

150 Percentage of SR&ED investment tax credits allocated from the partnership %

132 If not, when was the last claim? Year

155 Name of the person or firm who prepared this claim
Deloitte & Touche LLP

Certification and Election

I certify that I have examined the information provided on this form, and on the related schedules and attachments and it is true, correct, and complete.

I elect (choose) to use the following method to calculate my SR&ED expenditures and related investment tax credits (ITC) for the year. I understand that my election (choice) is irrevocable for this year.

160 I elect to use the proxy method under clause 37(8)(a)(ii)(B) 1 Yes X

162 I choose to use the traditional method 1 Yes

165 LUCY LOMBARDI
Name of authorized signing officer of the corporation, authorized partner, or individual

Signature

170 2008-06-26
Date

For Canada Revenue Agency use only

490 491 492

Part 2 – Scientific or Technological Project Information

Provide the information requested in Step 1 on separate sheets of paper for each project, and attach them to this form. If you have more than 20 projects, you only need to provide project descriptions for the 20 that are largest in term of dollar value. For step 2, provide the information requested on this form and complete Schedule E. For more information, see Guide T4088, *Claiming Scientific Research and Experimental Development.*

Step 1 – Detailed project description

Identify each of the projects you are claiming and use questions A to E below to help you provide the information we need to process your claim. If the project is continuing from last year and the objective has not changed or been achieved, you can use the same information that you provided last year for questions A, B and C. Include sufficient information to show how your project work meets the requirements of the SR&ED Program.

We recommend that you read Guide T4088 before you answer questions A to E. This will help you understand the type of information the Canada Revenue Agency needs to process your claim and will reduce or eliminate the need for you to submit more information. It will also help you avoid preparing unnecessary information. Most projects can be described in four pages or less. It would be helpful to take into account whether your project involved experimental development work or scientific research work, because the eligibility requirements for these are different. In general, **experimental development** work is done either in or outside a laboratory in order to achieve a technological advancement for creating new, or improving existing materials, devices, products, or processes. Scientific research work is done mostly in a laboratory setting to obtain new scientific knowledge.

A. **Scientific or technological objectives** – What is the scientific or technological objective of your project? Does this project involve scientific research or experimental development?

B. **Technology or knowledge base or level** – If your project work is mostly experimental development, what were the technological limitations of the products or processes before you started your project? If your project work is mostly scientific research, what was the extent of existing scientific knowledge in this area?

C. **Scientific or technological advancement** – What advancement in technology is being sought? What were the problems or challenges that could not be solved using commonly available techniques requiring you to seek an advance in the underlying technology to achieve the objective in A above? or what was the new scientific knowledge sought in your work? To what field of science or technology would the advance contribute?

D. **Description of work in the tax year** – Describe the work, including experiments and analyses, that you did in this tax year to achieve the technological or scientific objectives above. If all or part of the work that you are claiming was performed by contractors, include a description of the work performed on your behalf by the contractors or a copy of the statement of work from the contract.

E. **Supporting information** – What technical records or documents generated over the course of the work, such as records of trials, test results, progress and final reports, minutes of meetings, employee activity records, prototypes, and new products, are available to support your claim?

Step 2 – Project summary information

Total number of projects you are claiming in this tax year.	200	4
If you received an amount under the Industrial Research Assistance Program (IRAP) for SR&ED type work, please indicate the amount you received.	206	

Complete Schedule E to provide a list of all SR&ED projects for which you are claiming expenditures this year.

Part 3 – Summary of SR&ED Expenditures (nearest dollar)

Step 1 – Allowable SR&ED expenditures for SR&ED carried out in Canada			
SR&ED portion of salary or wages of employees directly engaged in SR&ED:			
• employees other than specified employees	300	+	616,634
• specified employees (do not include bonuses or remuneration based on profits) (see guide)	305	+	
Amounts deemed incurred in the year under subsection 78(4) (salary or wages)	310	+	
Unpaid amounts deemed not incurred in the year under subsection 78(4) 315			
Cost of materials consumed in the prosecution of SR&ED	320	+	
Cost of materials transformed in the prosecution of SR&ED	325	+	
SR&ED contracts performed on your behalf (complete Schedule F):			
• arm's length contracts	340	+	471,847
• non-arm's length contracts	345	+	
Lease costs of equipment used:			
• all or substantially all (90% of the time or more) for SR&ED	350	+	
• primarily (more than 50% but less than 90% of the time) for SR&ED. Enter only 50% of the lease costs if you use the proxy method. If you use the traditional method, enter "0".	355	+	
Overhead or other expenditures (enter "0" if you use the proxy method)	360	+	
Subtotal (add lines 300 to 360; do not add line 315)	365	=	1,088,481
Third-party payments (complete Schedule A)	370	+	
Total current SR&ED expenditures (add lines 365 and 370)	380	=	1,088,481
Capital expenditures (for ASA equipment, see guide)	390	+	
Total allowable SR&ED expenditures (add lines 380 and 390)	400	=	1,088,481

Step 2 – Pool of deductible SR&ED expenditures			
Amount from line 400			1,088,481
less			
• government and non-government assistance for expenditures included on line 400	430	–	
• SR&ED ITC claimed last year (other than ITC on shared-use equipment)	435	–	308,961
• sale of SR&ED capital assets (see guide) and other deductions	440	–	
add			
• previous year's ending balance in the pool of deductible SR&ED expenditures	450	+	
• amount of ITC recaptured in the preceding tax year	453	+	
• adjustments to the pool of deductible expenditures (complete Schedule B, Section 1)	454	+	
Amount available for deduction (If the amount is negative, enter "0" and add to income in the year)	455	=	779,520
Deduction claimed in the year	460	–	779,520
Current year's balance of deductible SR&ED expenditures applicable to future years (line 455 minus line 460)	470	=	

Step 3 – Qualified SR&ED expenditures for ITC purposes
Enter the breakdown between current and capital expenditures for ITC purposes.

	Line	Current Expenditures	Line	Capital Expenditures
Total expenditures for SR&ED (from lines 380 and 390)	492	1,088,481	496	
add				
• unpaid amounts (other than salaries or wages) from previous years that were paid in the year under subsection 127(26)	500 +			
• prescribed proxy amount (complete Schedule D); enter "0" if you use the traditional method	502 +	371,911		
• expenditures on shared-use-equipment (See Note 1)			504 +	
• qualified expenditures transferred to you (from Form T1146)	508 +		510 +	
less				
• government and non-government assistance, and contract payments	534 −		536 −	
• amounts from lines 552 and 554 of Schedule B, Section 2	552 −		554 −	
• amounts from lines 555 and 556 of Schedule C	555 −		556 −	
Subtotal	557 =	1,460,392	558 =	
SR&ED qualified expenditure pool (add lines 557 and 558)			559 =	1,460,392
add				
• Repayments of assistance and contract payments made in the year			560 +	
Total SR&ED expenditures that qualify for ITC purposes (add lines 559 and 560)*			570 =	1,460,392

*To claim an ITC on this amount, you must complete Schedule T2SCH31 – *Investment Tax Credit – Corporation*, or Form T2038(IND), *Investment Tax Credit (Individuals)*, whichever applies.

Note 1
The expenditure is deemed to be 1/4 of the capital cost of the equipment. Certain adjustments may be required if the equipment was purchased from a non-arm's length supplier (see the explanations for lines 522 and 524 in the guide).

Part 4 – Background Information

This information is used to administer the SR&ED program.

Expenditures for SR&ED performed by you (line 400 minus lines 340, 345, and 370) 605 616,634

A. Sources of funds for SR&ED
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

	Line	Canadian (%)	Line	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	

B. Business personnel
Total number of employees 630 401
SR&ED personnel (full-time SR&ED staff, plus full-time equivalent for staff engaged part-time in this activity):

Scientists and engineers	632	5	Technologists and tehnicians	634
Managers and administrators	636		Other technical supporting staff	638

C. Nature of SR&ED work
From the total you entered on line 605, estimate the approximate distribution of your SR&ED effort:

Basic research (no specific application in view)	650		Applied research (specific practical application in view)				652
Development of new: product	654		process	656	100.000	technical services	658
Improvement to existing: product	660		process	662		technical services	664

D. Specialized field of research
Indicate, if applicable, the percentage of the amount on line 605 attributed to the following fields of research:
Software development 670 Biotechnology 672 Environmental protection 674

Complete Claim Checklist

To speed up the processing of your claim, make sure you have:

1. Used the current version of Form T661 if you are filing a current-year claim	X
2. Signed the "Certification and Election" section in Part 1 of Form T661	X
3. Indicated the method you have chosen for reporting your SR&ED expenditures in fields 160 or 162 of Part 1	X
4. Provided a summary of information for each project, with a breakdown of expenditures (labour, materials and contracts) as per Schedule E	X
5. Submitted a detailed project description of your 20 largest projects in terms of their dollar value	X
6. Retained documents prepared to support the SR&ED expenditures claimed in Part 3. If you forget to claim an expenditure, you have up to 12 months after the filing-due date of your tax return for the year to submit an amended Form T661	X
7. Completed Part 4 - Background Information	X
8. Completed schedule A, B, C, D, E and F, if they apply to your situation, and attached to form T661	X
9. Filed a completed Schedule T2SCH31, *Investment Tax Credit – Corporations*, or Form T2038 (IND), *Investment Tax Credit (Individuals)*, to claim ITCs on your qualified SR&ED expenditures	X

All the information requested in this form including the attachments, schedules and any other document to support your expenditures is prescribed information. You have to file the information that applies to your claim, along with Schedule T2SCH31 or Form T2038(IND), within 12 months of the filing-due date of your Income tax return for the year you incurred the expenditures. If you do not meet this reporting deadline, your claim may be rejected.

Schedule A – Third-Party Payments for SR&ED

You must complete a Schedule A for each third-party payment for SR&ED (attach to Form T661).

Schedule B – Special Situations (attach to Form T661).

Section 1 – Adjustments to the pool of deductible SR&ED expenditures incurred in Canada

• Repayments of government and non-government assistance (include only the repayments of assistance that previously reduced the deductible SR&ED expenditure pool)	445	+	
• SR&ED expenditure pool transfer from amalgamation or wind-up	452	+	
Total (add lines 445 and 452)	454	=	

Report on line 454 in Part 3, Step 2 of Form T661

Section 2 – Adjustments to the qualified SR&ED expenditures for ITC purposes

			Current Expenditures			Capital Expenditures
• Unpaid amounts (other than salary or wages on line 315) deemed not to be incurred in the year under subsection 127(26)	520	–				
• Current expenditures for SR&ED contract paid or payable to, or for the benefit of a person or partnership that is not a taxable supplier in respect of the expenditures	528	–				
• Prescribed expenditures (Section 2902 of the *Regulations*)	530	–		532	–	
• Other deductions (see guide)	548	–		550	–	
Total (add lines 520, 528, 530, and 548, also add lines 532 and 550)	552	=		554	=	

Report on lines 552 and 554 respectively in Part 3, Step 3 of Form T661

Schedule C – Non-Arm's Length Transactions (attach to Form T661).

Adjustments to the qualified SR&ED expenditures for ITC purposes

			Current Expenditures			Capital Expenditures
• Purchases of goods and services from non-arm's length suppliers (except for shared-use equipment) (see note 1)	522	–		524	–	
• Expenditures for non-arm's length SR&ED contracts (from line 345)	526	–				
• Assistance allocated to you (from Form T1145)	538	–		540	–	
• Qualified expenditures you transferred (from Form T1146)	544	–		546	–	
Total (add lines 522, 526, 538, and 544, also add lines 524, 540, 546)	555	=		556	=	

Report on line 555 and 556 respectively in Part 3, Step 3 of Form T661

Note 1

Subsections 127(11.6) to (11.8) provide rules for determining a taxpayer's expenditures to services rendered by, or property acquired from, a non-arm's length supplier. On line 522, enter the difference, if any, between the amount included in your SR&ED expenditure pool for the purchases of goods and services from non-arm's length suppliers and the expenditure's deemed amount under subsection 127(11.6) (read the Guide).

T661 Schedule D – Calculation of Salary Base and Prescribed Proxy Amount

If you are using the proxy method, complete this calculation table and attach it to Form T661.

This table will help you to calculate the prescribed proxy amount (PPA) to enter on line 502 of Form T661. You can only claim a PPA if you elected in Part 1 of Form T661 (line 160) to use the proxy method for the year.

The PPA is 65% of the salary base determined in Section A. The salary base is the total of salary or wages paid to and incurred for the employees directly engaged in SR&ED in Canada during the year.

Special rules apply for specified employees. Calculate your salary base in Section A, the PPA in Section B, and the salary or wages of specified employees eligible to be included in the salary base in Section C.

Section A – Salary base

Salary or wages of employees directly engaged in SR&ED, other than specified employees (from line 300)	810 +	616,634
Less: Remuneration based on profits, bonuses, and taxable benefits under sections 6 and 7 of the Act, included on line 810 above	812 –	44,464
Subtotal (line 810 minus line 812)	814 =	572,170
Plus: Total salary or wages of specified employees directly engaged in SR&ED (per Section C, total of column 6 below)	816 +	
Salary base (total of lines 814 and 816)	818 =	572,170

Section B – Prescribed Proxy Amount

Calculate 65 % of the salary base per line 818 Report the PPA on line 502 of Part 3, Step 3 of Form T661.	820 =	371,911

In certain situations, an overall cap on the PPA may limit the amount otherwise determined (see Table 7 in the guide).

Section C – Determining the salary or wages of specified employees

Special rules apply to restrict the amount of salary or wages of specified employees that you can include in the salary base. Use the chart below to calculate this amount.

850 Column 1	852 Column 2	854 Column 3	856 Column 4	Column 4a	858 Column 5**	860 Column 6
Name of specified employee	Total salary or wages for the year (SR&ED and non-SR&ED)*	Percentage of time spent on SR&ED in Canada (maximum 75%)	Amount in column 2 multiplied by percentage in column 3	Number of days in taxation year employed (maximum 365 days)	2.5 x A x B ÷365	Amount in column 4 or 5, whichever amount is less

Total (enter total of column 6 amounts on line 816 in Section A above).

* Do not include bonuses, remuneration based on profits, or taxable benefits under sections 6 and 7 of the *Act*.

** **A** is the year's maximum pensionable earnings (section 18 of the *Canada Pension Plan*) for the calendar year in which your tax year ends. The year's maximum pensionable earnings for 2008 are $44, 900 (total $44, 900 x 2.5 = $112, 250), for 2007 are $43,700 (total $43,700 x 2.5 = $109,250), for 2006 they are $42,100 (total $42,100 x 2.5 = $105,250), and for 2005 they are $41,100 (total $41,100 x 2.5 = $102,750).

B is the number of days in the taxation year that you employ the individual.

T661 Schedule E – List of all SR&ED projects claimed in the year (attach to Form T661)

For each project you are claiming, provide the following information using the table below. Expenditures should be recorded and allocated on a project basis.

210 Project identification: code or name	212 Start date (yyyy/mm/dd)	214 Finish date (yyyy/mm/dd) Actual or expected	216 Total labour expenditures in tax year	218 Total expenditures of materials in tax year	220 Total contract expenditures in tax year
1. P1 - Power system assets, equipmen	2006-01-01	2008-06-30	149,881		99,140
2. P2 - Transformer and substation stal	2006-01-01	2008-12-31	176,252		68,277
3. P3 - Electric Power Distribution Syste	2006-01-01	2008-12-31	153,008		37,500
4. P4 - Developing & applying systems,	2006-01-01	2009-02-28	137,492		266,930
		Total	616,633		471,847

Use copies of this schedule if you have more than 50 projects and attach them to Form T661.

T661 Schedule F – Arm's Length and Non-Arm's Length SR&ED Contracts (attach to Form T661)

Complete this schedule only if the total dollar amount per contractor for the year is greater than $30,000. If necessary, use copies of this schedule and attach them to Form T661.

Section A – Number of contractors for whom you have to report and provide details in Sections B and C

Arm's length contractors (complete section B below)	6	900
Non-arm's length contractors (complete section C below)		920

Section B – Complete this section for each arm's length contractor

902 Name of contractor	904 Contractor's Business No. or GST Registration No.	906 Number of contracts per contractor	908 Total dollar amount per contractor greater than $30,000	910 Project code for expenditures claimed in the year (if available)	912 Total contract expenditures in tax year
SNC Lavalin Nexacor	898959556	1	85,270	P2	39,960
Kinectrics	864020920	1	37,500	P1	37,500
Giffels	102088317RT0001	1	86,700	P1	86,700
T&W Info-Systems Ltd	R105429591	1	77,200	P4	77,200
Util-Assist	842772741RT0001	1	119,612	P4	119,612
Enermodal	R101638848	1	50,409	P4	50,409
The total of column 912 is included in the total of line 340 in Part 3, Step 1 of Form T661.				Total	411,381

Section C – Complete this section for each non-arm's length contractor

922 Name of contractor	924 Contractor's Business No. or GST Registration No.	926 Number of contracts per contractor	928 Total dollar amount per contractor greater than $30,000	930 Project code for expenditures claimed in the year (if available)	932 Total contract expenditures in tax year
The total of column 932 is included in the total of line 345 in Part 3, Step 1 of Form T661.				Total	

FINAL

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* X Yes ☐ No

Corporation's Legal Name *(including punctuation)*
POWERSTREAM INC.

Mailing Address
161 Cityview Blvd
VAUGHAN
ON CA L4H 0A9

Has the mailing address changed since last filed CT23 Return? X Yes
Date of Change year month day

Registered/Head Office Address
161 Cityview Blvd
VAUGHAN
ON CA L4H 0A9

Location of Books and Records
161 Cityview Blvd
VAUGHAN
ON CA L4H 0A9

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
GERI YIN	(905) 532-4635	

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

Former Corporation Name *(Extra-Provincial Corporations only)* X *Not Applicable* (MGS)

Ontario Corporations Tax Account No. (MOF)
1800391

This Return covers the Taxation Year
Start (year month day) 2007-01-01
End (year month day) 2007-12-31

Date of Incorporation or Amalgamation (year month day) 2005-11-01

Ontario Corporation No. (MGS) 1677786

Canada Revenue Agency Business No. If applicable, enter
85750 3346 RC0002

Jurisdiction Incorporated: Ontario

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced year month day
Ceased year month day
X *Not Applicable*

Preferred Language / *Langue de préférence*
X English *anglais* ☐ French *français*

Ministry Use

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s)

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ X No Change

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
LUCY LOMBARDI

Title: D ☐ Director O X Officer P ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
2 [ ] Other Private
3 [ ] Public
4 [ ] Non-share Capital
5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)
2 [ ] Family Fishing corporation s.1(2)
3 [ ] Mortgage Investment corporation s.47
4 [ ] Credit Union s.51
5 [ ] Bank Mortgage subsidiary s.61(4)
6 [ ] Bank s.1(2)
7 [ ] Loan and Trust corporation s.61(4)
8 [ ] Non-resident corporation s.2(2)(a) or (b)
9 [ ] Non-resident corporation s.2(2)(c)
10 [ ] Mutual Fund corporation s.48
11 [ ] Non-resident owned Investment corporation s.49
12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
14 [ ] Bare Trustee corporation
15 [ ] Branch of Non-resident s.63(1)
16 [ ] Financial institution prescribed by Regulation only
17 [ ] Investment Dealer
18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
19 [X] Hydro successor, municipal electrical utility or subsidiary of either
20 [ ] Producer and seller of steam for uses other than for the generation of electricity
21 [ ] Insurance Exchange s.74.4
22 [ ] Farm Feeder Finance Co-operative corporation
23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired — year / month / day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
	X	Was the corporation inactive throughout the taxation year?
X		Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
	X	the Carry-back of a Loss?
X		an Overpayment?
	X	a Specified Refundable Tax Credit?
X		Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

ELECTRICITY DISTRIB

Income Tax

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

		Line	Amount
Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	35,091,498
Subtract: Charitable donations	–	1	106,170
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	
Net capital losses (page 16) ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	34,985,328

Addition to taxable income for unused foreign tax deduction for federal purposes + 11 ______

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) = 20 34,985,328

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 34,985,328 x 30 100.0000 % Ontario Allocation x 12.5 % x 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ______ ÷ 73 (Total Days) 365 = + 29 ______

From 10 (or 20 if applicable) 34,985,328 x 30 100.0000 % Ontario Allocation x 14 % x 34 (Days after Dec. 31, 2003) 365 ÷ 73 (Total Days) 365 = + 32 4,897,946

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 4,897,946

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 33,235,180

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 35,294,289

Add: Losses of other years deducted for federal purposes (fed.s.111) + 52 ______

Subtract: Losses of other years deducted for Ontario purposes (s.34) – 53 ______

= 35,294,289 ▶ 54 35,294,289

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) 55 400,000

Ontario Business Limit Calculation

320,000 x 31 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ______ ÷ ** 365 = + 46 ______

400,000 x 34 (Days after Dec. 31, 2003) 365 ÷ ** 365 = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x 48 100.0000 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 400,000

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 400,000 (Least of 50, 54 or 45) = 60 400,000

* *Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** *Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** *Note: Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate

Number of Days in Taxation Year

7 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ____ ÷ Total Days: 73 365) = + 89 ____ .

8.5 % x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 90 8.5000

IDSBC Rate for Taxation Year 89 + 90 = 78 8.5000

Claim: From 60 400,000 x From 78 8.5000 % = 70 34,000

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From 10 (or 20 if applicable) + 80 34,985,328

If you are a member of an associated group (X) 81 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
			+ 82	
			+ 83	
			+ 84	

Aggregate Taxable Income 80 + 82 + 83 + 84, etc. = 85 34,985,328

Number of Days in Taxation Year

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ____ ÷ Total Days: 73 365) = + 115 ____

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 116 400,000

115 + 116 = 400,000 ▶ − 114 400,000

(If negative, enter nil) = 86 34,585,328

Calculation of Specified Rate for Surtax

Number of Days in Taxation Year

4.6670 % x (Days after Dec. 31, 2002: 38 365 ÷ Total Days: 73 365) = + 97 4.6670

From 86 34,585,328 x From 97 4.6670 % = 87 1,614,097

From 87 1,614,097 x From 60 400,000 ÷ From 114 400,000 = 88 1,614,097

Surtax Lesser of 70 or 88 = 100 34,000

*** Note: Short Taxation Years*** – Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

110 ____

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits + 120 ____

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) − From 56 400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 34,000 ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 400,000

*Ontario Allocation

Lesser of 56 or 121 + 122 400,000

120 − 56 + 122 = 130 ____

Taxable Income + From 10 34,985,328

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) − From 56 400,000

Add: Adjustments for Surtax on Canadian-controlled private corporations + From 122 400,000

Subtract: Taxable Income 10 34,985,328 X Allocation % to jurisdictions outside Canada − 140 ____

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses − 141 2,165,279

10 − 56 + 122 − 140 − 141 = 142 32,820,049

Claim

				Number of Days in Taxation Year	
143 ____ (Lesser of 130 or 142)	X From 30 100.0000 % (Ontario Allocation)	X	1.5 %	X Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ____ ÷ Total Days 73 365	= + 154 ____
143 ____ (Lesser of 130 or 142)	X From 30 100.0000 % (Ontario Allocation)	X	2 %	X Days after Dec. 31, 2003: 34 365 ÷ Total Days 73 365	= + 156 ____

M&P claim for taxation year 154 + 156 = 160 ____

** **Note:** Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

= 161 ____

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

= 162 ____

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170 ____

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 ____ Credit Claimed 180 ____

Subtotal of Income Tax

40 − 70 + 100 − 110 − 160 − 161 − 162 − 170 − 180 = 190 4,897,946

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192 34,956

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. 204 Name of Production
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194
Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896
Applies to employment of eligible apprentices. 202 12
Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203 52,960

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 87,916

Specified Tax Credits ***Applied to reduce Income Tax*** = 225 87,916

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 4,810,030

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation + 240 616,700,419

Total Revenue of the corporation + 241 614,834,000

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Total Assets		Total Revenue
			+ 243		+ 244	
			+ 245		+ 246	
			+ 247		+ 248	

Aggregate Total Assets 240 + 243 + 245 + 247, etc. = 249 616,700,419

Aggregate Total Revenue 241 + 244 + 246 + 248, etc. = 250 614,834,000

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 35,248,000 (If negative, enter zero) X From 30 100.0000 % X (Ontario Allocation) 4 % = 276 1,409,920

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* – 277

Subtract: Income Tax – From 190 4,897,946

Net CMT Payable (If negative, enter Nil on Page 17.) = 280 -3,488,026

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From 190 4,897,946

Gross CMT Payable + From 276 1,409,920

Subtract: Foreign Tax Credit for CMT purposes – From 277

If 276 – 277 is negative, enter NIL in 290 = 1,409,920 – 290 1,409,920

Income Tax eligible for CMT Credit = 300 3,488,026

B. Income Tax (after deduction of specified credits) + From 230 4,810,030

Subtract: CMT credit used to reduce income taxes – 310

Income Tax = 320 4,810,030 *Transfer to page 17*

If A & B apply, 310 ***cannot exceed the lesser of*** 230, 300 ***and your CMT credit carryover available*** 2333.

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	149,433,000
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	45,395,000
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	14,324,000
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	328,906,786
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	11,505,165
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	53,454
Subtotal	=	370	549,617,405
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	−	371	13,979,680
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	−	372	
Total Paid-up Capital	=	380	535,637,725
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	−	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	−	382	
Net Paid-up Capital	=	390	535,637,725

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations. (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	41,257
Total Eligible Investments	=	410	41,257

continued on Page 10

Total Assets (Int.B. 3015R)

		DOLLARS ONLY
Total Assets per balance sheet	+ 420	616,645,000
Mortgages or other liabilities deducted from assets	+ 421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+ 422	55,419
Subtract: Investment in partnership(s)/joint venture(s)	– 423	
Total Assets as adjusted	= 430	616,700,419
Amounts in 360 and 361 (if deducted from assets)	+ 440	11,505,165
Subtract: Amounts in 371, 372 and 381	– 441	13,979,680
Subtract: Appraisal surplus if booked	– 442	
Add or Subtract: Other adjustments (specify on an attached schedule)	± 443	
Total Assets	= 450	614,225,904

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	= 460	35,978
Taxable Capital 390 – 460	= 470	535,601,747

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	614,834,000
Total Assets (as adjusted)	From 430	616,700,419

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

		Number of Days in Taxation Year				
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)	÷ 73	365 (Total Days)	= + 501	
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007)	÷ 73	365 (Total Days)	= + 502	
12,500,000	x	38 365 (Days after Dec. 31, 2006 and before Jan. 1, 2008)	÷ 73	365 (Total Days)	= + 504	12,500,000
15,000,000	x	39 (Days after Dec. 31, 2007)	÷ 73	365 (Total Days)	= + 505	

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

		Number of Days in Taxation Year				
0.3 %	x	556 (Days before Jan. 1, 2007)	÷ 73	365 (Total Days)	= + 511	%
0.285 %	x	557 365 (Days after Dec. 31, 2006 and before Jan. 1, 2009)	÷ 73	365 (Total Days)	= + 512	0.2850 %

Capital Tax Rate 511 + 512 = 516 0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470	535,601,747									
− From 503	12,500,000									
= 471	523,101,747	x	From 30	100.0000 % Ontario Allocation	x	From 516	0.2850 % Capital Tax Rate	x	555 Days in taxation year 365 / 365 (366 if leap year) *If floating taxation year, refer to Guide.*	= + 523 1,490,840 *Transfer to 543 on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. [ ] 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. [ ] 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation
Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 + From 470 ______ .

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
			+ 531	.
			+ 532	.
			+ 533	.
Aggregate Taxable Capital 470 + 531 + 532 + 533, etc.			= 540	.

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 ______ . ÷ From 540 ______ . x From 503 ______ . = 541 ______ .

Transfer to 542 in Section E below

Ss.69(2.1) Election Filed

591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+ From 470 ______ .
− 542 ______ .
= 471 ______ . x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) x 555 365 (Days in taxation year) / * 365 (366 if leap year) = + 523 ______ . (**Total Capital Tax for the taxation year**)

Transfer to 543 and complete the return from that point

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 ______ . x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) = + 561 ______ .

− Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 − From 995 ______ .

= 562 ______ .

Capital Tax 562 ______ . x 555 365 (Days in taxation year) / * 365 (366 if leap year) = 563 ______ . (**Total Capital Tax for the taxation year**)

Transfer to 543 and complete the return from that point

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits = 543 1,490,840 .

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* − 546 .

Capital Tax 543 − 546 *(amount cannot be negative)* = 550 1,490,840 .

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ________ . x 567 ______ % x From 30 100.0000 % x 555 365 / 365* = + 569 ________ .

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 | Capital Tax Rate (1) (Refer to Guide) | Ontario Allocation | Days in taxation year (366 if leap year)

570 ________ . x 571 ______ % x From 30 100.0000 % x 555 365 / 365* = + 574 ________ .

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount | Capital Tax Rate (2) (Refer to Guide) | Ontario Allocation | Days in taxation year (366 if leap year)

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575 ________ .

* *If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – 585 ________ .

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions 575 – 585 = 586 ________ .

Transfer to 543 on Page 12

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements 587 ________ . x 2 % = 588 ________ .

Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)

Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – 589 ________ .

Premium Tax 588 – 589 = 590 ________ .

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 35,400,459 • *Transfer to Page 15*

Add:

Federal capital cost allowance	+	601	31,507,824 •
Federal cumulative eligible capital deduction	+	602	694,549 •
Ontario taxable capital gain	+	603	2,165,279 •
Federal non-allowable reserves. Balance beginning of year	+	604	8,175,149 •
Federal allowable reserves. Balance end of year	+	605	•
Ontario non-allowable reserves. Balance end of year	+	606	11,505,165 •
Ontario allowable reserves. Balance beginning of year	+	607	•
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+	608	•
Federal resource allowance *(Refer to Guide)*	+	609	•
Federal depletion allowance	+	610	•
Federal foreign exploration and development expenses	+	611	•
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+	617	•

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

612 ______ • x 5 / 12.5 x (33 [Days after Dec. 31, 2002 and before Jan. 1, 2004] ______ ÷ 73 365 [Total Days]) = + 633 ______ •

612 ______ • x 5 / 14 x (34 [Days after Dec. 31, 2003] 365 ÷ 73 365 [Total Days]) = + 634 ______ •

Total add-back amount for Management fees, etc. 633 + 634 = ______ • ▶	+	613	•
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+	615	779,520 •
Add any negative amount in 473 from Ont. CT23 Schedule 161	+	616	•
Federal allowable business investment loss	+	620	•
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+	614	•

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 54,827,486 • ▶ 640 54,827,486 • *Transfer to Page 15*

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+	650	31,507,824 •
Ontario cumulative eligible capital deduction	+	651	694,549 •
Federal taxable capital gain	+	652	2,165,279 •
Ontario non-allowable reserves. Balance beginning of year	+	653	8,175,149 •
Ontario allowable reserves. Balance end of year	+	654	•
Federal non-allowable reserves. Balance end of year	+	655	11,505,165 •
Federal allowable reserves. Balance beginning of year	+	656	•
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+	657	•
Ontario depletion allowance	+	658	•
Ontario resource allowance *(Refer to Guide)*	+	659	•
Ontario current cost adjustment *(Attach schedule)*	+	661	•
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+	675	•

Subtotal of deductions for this page 650 to 659 + 661 + 675 681 54,047,966 • *Transfer to Page 15*

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1		From ± 600	35,400,459
Total of Additions on page 14		From = 640	54,827,486
Sub Total of deductions on page 14	From = 681 54,047,966		

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 ______

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 ______ x 100 / (From 30 100.0000 Ontario Allocation)] − From 662 ______ = 663 ______

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 ______ x 30 % x 100 / (From 30 100.0000 Ontario allocation)] = 666 ______

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 ______ x 100 % x 100 / (From 30 100.0000 Ontario allocation)] = 668 ______

Number of Employees accommodated 669 ______

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 ______ x 30 % x 100 / (From 30 100.0000 Ontario allocation)] = 671 ______

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 ______ x 15 % x 100 / (From 30 100.0000 Ontario allocation)] = 673 ______

Ontario allowable business investment loss	+ 678	
Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161**	+ 679	1,088,481
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	+ 677	
Total of other deductions allowed by Ontario *(Attach schedule)*	+ 664	

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 55,136,447 ▶ 680 55,136,447

Net income (loss) for Ontario Purposes 600 + 640 − 680 = 690 35,091,498

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day		Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 2000-05-31	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2001-05-31	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2002-05-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2003-05-31	820	830	840	853	873
804	5th preceding taxation year 2004-05-31	821	831	841	854	874
805	4th preceding taxation year 2004-12-31	822	832	842	855	875
806	3rd preceding taxation year 2005-10-31	823	833	843	856	876
807	2nd preceding taxation year 2005-12-31	824	834	844	857	877
808	1st preceding taxation year 2006-12-31	825	835	845	858	878
809	Current taxation year 2007-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2005-10-31	911	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320		4,810,030
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		1,490,840
Premium Tax	+ From 590		
Total Tax Payable	=	950	6,300,870
Subtract: Payments	−	960	6,933,283
Capital Gains Refund (s.48)	−	965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	−	985	
Specified Tax Credits *(Refer to Guide)*	−	955	
Other, specify	−		
Balance	=	970	-632,413
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	632,413
Apply to (year month day)		980	

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

LUCY LOMBARDI

Title

DIRECTOR, CORPORATE FINANCE

Full Residence Address

Signature

Date

2008-06-26

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Amounts deducted for income tax purposes in excess of amounts booked (Retain calculations. Do not submit.) (Int.B. 3012R)

Title TAX AMOUNT IN EXCESS OF ACCOUNTING

Description	Amount
CUMULATIVE	13,979,680 00
Total	13,979,680 00

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)			± 2100	21,148,000
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102			
Equity income from corporations	+ 2103			
Share of partnership(s)/joint venture(s) income	+ 2104			
Dividends received/receivable deductible under fed.s.112	+ 2105			
Dividends received/receivable deductible under fed.s.113	+ 2106			
Dividends received/receivable deductible under fed.s.83(2)	+ 2107			
Dividends received/receivable deductible under fed.s.138(6)	+ 2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) ____ x 3	+ 2109			
Subtotal	=		– 2110	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	+ 2111	14,100,000		
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112			
Equity losses from corporations	+ 2113			
Share of partnership(s)/joint venture(s) losses	+ 2114			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115			
Subtotal	=	14,100,000	+ 2116	14,100,000

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	+ 2117		or – 2118	
** Fed.s.85.1	+ 2119		or – 2120	
** Fed.s.97	+ 2121		or – 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or – 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or – 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or – 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			– 2155	

Subtotal (Additions) =		+ 2129	
Subtotal (Subtractions) =		– 2130	
** Other adjustments		± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131		= 2132	35,248,000
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss		± 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in ***Part 2: Continuity of CMT Losses Carried Forward.***)		= 2134	35,248,000
Deduct: * CMT losses: pre-1994 Loss	+ From 2210		
* CMT losses: other eligible losses	+ 2211		
	=	– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	35,248,000

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)			+ 2201
Add: Current year's losses	+ 2202		
Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203		
Losses from predecessor corporations on wind-up NOTE (3)	+ 2204		
Amalgamation (X) 2205 Yes Wind-up (X) 2206 Yes			
Subtotal	=	▶	+ 2207
Adjustments (attach schedule)			± 2208
CMT losses available 2201 + 2207 ± 2208			= 2209
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210		
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211		
Losses expired during the year	+ 2212		
Subtotal	=	▶	− 2213
Balances at End of Year NOTE (5) 2209 − 2213			= 2214

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and Indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 2000-05-31	2260	2280
2241	8th preceding taxation year 2001-05-31	2261	2281
2242	7th preceding taxation year 2002-05-31	2262	2282
2243	6th preceding taxation year 2003-05-31	2263	2283
2244	5th preceding taxation year 2004-05-31	2264	2284
2245	4th preceding taxation year 2004-12-31	2265	2285
2246	3rd preceding taxation year 2005-10-31	2266	2286
2247	2nd preceding taxation year 2005-12-31	2267	2287
2248	1st preceding taxation year 2006-12-31	2268	2288
2249	Current taxation year 2007-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . . − From 190

Subtotal (If negative, enter NIL) . . . = ▶ − 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 − 2305 . . . = ▶ + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . . + 2325

Amalgamation (X) 2315 Yes Wind-up (X) 2320 Yes

Subtotal 2301 + 2310 + 2325 . . . . = 2330

Adjustments *(Attach schedule)* . . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . . + 2334

Subtotal . . . . = ▶ − 2335

Balance at End of Year NOTE (4) 2333 − 2335 . . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 2000-05-31	2360	2380
2341	8th preceding taxation year 2001-05-31	2361	2381
2342	7th preceding taxation year 2002-05-31	2362	2382
2343	6th preceding taxation year 2003-05-31	2363	2383
2344	5th preceding taxation year 2004-05-31	2364	2384
2345	4th preceding taxation year 2004-12-31	2365	2385
2346	3rd preceding taxation year 2005-10-31	2366	2386
2347	2nd preceding taxation year 2005-12-31	2367	2387
2348	1st preceding taxation year 2006-12-31	2368	2388
2349	Current taxation year 2007-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 ***must equal amount in*** 2336.

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-05-31					
9th Prior Year	2000-05-31					
8th Prior Year	2001-05-31					
7th Prior Year	2002-05-31					
6th Prior Year	2003-05-31					
5th Prior Year	2004-05-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-10-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-05-31						
2000-05-31						
2001-05-31						
2002-05-31						
2003-05-31						
2004-05-31						
2004-12-31						
2005-10-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-05-31						
2000-05-31						
2001-05-31						
2002-05-31						
2003-05-31						
2004-05-31						
2004-12-31						
2005-10-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-05-31					
9th Prior Year	2000-05-31					
8th Prior Year	2001-05-31					
7th Prior Year	2002-05-31					
6th Prior Year	2003-05-31					
5th Prior Year	2004-05-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-10-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-05-31						
2000-05-31						
2001-05-31						
2002-05-31						
2003-05-31						
2004-05-31						
2004-12-31						
2005-10-31						
2005-12-31						
2006-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-05-31						
2000-05-31						
2001-05-31						
2002-05-31						
2003-05-31						
2004-05-31						
2004-12-31						
2005-10-31						
2005-12-31						
2006-12-31						
Total						

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 622
Oshawa ON L1H 8H6

CT23 Change of Address

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

CT23 Change of Address

Federal Account Number 85750 3346 RC0002

Effective Date of Change . . . .

New Mailing Address:

C/O . . . .

Address 1 . . . . 161 Cityview Blvd

Address 2 . . . .

City . . . . VAUGHAN

Province . . . . ON

Country . . . . CA

Postal Code L4H 0A9

Zip Code . . . .

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

DUE TO RELATED PARTIES	+	16,748,000
CURRENT PORTION OF CUSTOMER'S DEPOSIT	+	1,484,556
CONSTRUCTION DEPOSIT	+	22,837,230
LIABILITY FOR SUBDIVISION DEVELOPTMENT	+	4,144,000
NOTES PAYABLE	+	156,310,000
DEBENTURES PAYABLE	+	100,000,000
REGULATORY LIABILITIES	+	11,011,000
CUSTOMER'S DEPOSITS	+	11,681,000
OTHER LIABILITIES	+	4,691,000
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total Transfer to 353 of the CT23	=	328,906,786

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital - Partnerships/Joint Ventures

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Name of Partnership or Joint Venture	Share of Partnership Using Profit Sharing Ratio (%)	Partnership/Joint Venture Paid-up Capital	Corporation's Share of Partnership/Joint Venture Paid-up Capital
THE ENERCONNECT LIMITED PARTNERSHIP	4.1041 %	1,302,464	+ 53,454
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
		Total *Transfer to* 362 *of the CT23*	= 53,454

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Eligible Investments - Partnerships/Joint Ventures

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Name of Partnership or Joint Venture	Share of Partnership Using Profit Sharing Ratio (%)	Partnership/Joint Venture Investments		Corporation's Share of Partnership/Joint Venture Investments
THE ENERCONNECT LIMITED PARTNERSHIP	4.1041 %	1,005,273	+	41,257
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
	%		+	
		Total Transfer to 407 of the CT23	=	41,257

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Share of Total Assets - Partnerships/Joint Ventures

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Name of Partnership or Joint Venture	Share of Partnership Using Profit Sharing Ratio (%)	Partnership/Joint Venture Total Assets	Corporation's Share of Partnership/Joint Venture Total Assets
THE ENERCONNECT LIMITED PARTNERSHIP	4.1041 %	1,350,336	+ 55,419
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
	%		+
		Total *Transfer to* 422 *of the CT23*	= 55,419

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Charitable Donations and Gifts
Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

- For use by a corporation to claim any of the following:
  - Charitable donations;
  - Gifts to Her Majesty in right of Ontario, to Ontario crown agencies, or to Ontario Crown foundations;
  - Gifts to Canada or a province;
  - Gifts of certified cultural property; or
  - Gifts of certified ecologically sensitive land.
- The donations and gifts are eligible for a five year carry-forward.
- Use this schedule to show a credit transfer following an amalgamation or wind-up of subsidiary as described under subsection 87(1) and 88(1) of the federal *Income Tax Act* (Canada).
- For donations and gifts made after March 22, 2004, subsection 34(1.1) of the *Corporations Tax Act* parallels subsection 110.1(1.2) of the *Income Tax Act* and provides as follows:
  - where a particular corporation has undergone a change of control, for taxation years that end on or after the change of control, no corporation can claim a deduction for a gift made by a particular corporation to a qualified donee before the change of control;
  - if a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the change 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.
- File one completed copy of this schedule with your CT23.

Part 1 – Charitable Donations

Charitable Donations at end of preceding taxation year			+	A
Deduct: Donations expired after 5 taxation years			–	B
Charitable donations at beginning of taxation year			=	C
Add: Donations transferred on amalgamation or wind-up of subsidiary	+	D		
Total current year charitable donations made	+	106,170 E		
Subtotal D + E	=	106,170	►	106,170 F
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)			–	G
Total donations available **C + F – G**			=	106,170 H
Deduct: Amount applied against taxable income (amount **U**, Part 2)			–	106,170 U
Charitable donations closing balance			=	I

Part 2 – Maximum Deduction Calculation for Donations

Ontario net income for tax purposes multiplied by 75% = 26,318,624 J

Note: *For credit unions the Ontario net income for tax purposes is the amount before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.*

Ontario taxable capital gains arising in respect of gifts of capital property + K

Ontario taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ITA + L

Add the lesser of:

1. The amount of the recapture of capital cost allowance in respect of charitable gifts M
2. **The lesser of:**
   - 2a. Proceeds of dispositions less outlays and expenses N
   - 2b. The capital cost O

   The lesser of **N** and **O** ► P

The lesser of **M** and **P** ► + Q

Subtotal K + L + Q = R

25% X R = S

Maximum deduction allowable J + S = 26,318,624 T

Claim for charitable donations (not exceeding the lesser of **H** from Part 1, **T** and net income for tax purposes) 106,170 U

Enter in 1 *of the CT23*

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 3 – Gifts to Her Majesty in right of Ontario

For use by a corporation claiming gifts to Her Majesty in right of Ontario, to Ontario Crown Agencies, or to Ontario Crown Foundations.

Gifts to Ontario Crown Agency or Ontario Crown Foundation at end of the preceding taxation year		+	
Deduct: Gifts expired after 5 years		–	
Gifts to Ontario Crown Agency or Ontario Crown Foundation at the beginning of the taxation year		=	
Add: Gifts transferred on amalgamation or wind-up of a subsidiary	+		
Total current year gifts	+		
Subtotal	=	▶	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		–	
Total gifts available		=	
Deduct: Amount applied against taxable income 2 of the CT23		–	
Gifts to Ontario Crown Agency or Ontario Crown Foundation closing balance		=	

Foundation Name	Date of Donation	Amount $

Total gifts to Her Majesty in right of Ontario =

Part 4 – Maximum Deduction Calculation for Gifts to Her Majesty in Right of Ontario

Deduction is the lesser of:

1. Ontario Net Income before deductions of gifts after deducting charitable donations and gifts to Her Majesty in right of Canada or a province other than Ontario			34,985,328 V
2. **Lesser of:**			
2a. Ontario Net Income for the taxation year	35,091,498 W		
2b. Gifts made in the taxation year or any of the five preceding taxation years to Her Majesty in Right of Ontario, an Ontario Crown Agency or an Ontario Crown Foundation	X		
The lesser of **W** and **X**		▶	Y
Maximum deduction allowable the lesser of **V** and **Y**			Z

Transfer to 2 *of the CT23*

Part 5 – Gifts to Canada or a province other than Ontario

Gifts to Canada or a province other than Ontario at the end of the preceding year		+	
Deduct: Gifts to Canada or a province other than Ontario expired after five taxation years		–	
Gifts to Canada or a province other than Ontario at the beginning of the taxation year		=	
Add: Gifts to Canada or a province other than Ontario transferred on amalgamation or wind-up of a subsidiary	+		
Total current year Gifts to Canada or a province other than Ontario *(Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date.)*	+		
Subtotal	=	▶	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		–	
Total gifts to Canada or a province other than Ontario available		=	
Deduct: Amount applied against taxable income		–	
Gifts to Canada or a province other than Ontario closing balance		=	

Ontario Charitable Donations and Gifts

Schedule 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 6 – Gifts of certified cultural property

Gifts of certified cultural property at the end of the preceding taxation year		+	
Deduct: Gifts of certified cultural property expired after five years		–	
Gifts of certified cultural property at the beginning of the taxation year		=	
Add: Gifts of certified cultural property transferred on amalgamation or wind-up of a subsidiary	+		
Total current year gifts of certified cultural property	+		
Subtotal	=	►	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		–	
Total gifts of certified cultural property available		=	
Deduct: Amount applied against taxable income		–	
Gifts of certified cultural property closing balance		=	

Part 7 – Gifts of certified ecologically sensitive land

Gifts of certified ecologically sensitive land at the end of the preceding taxation year		+	
Deduct: Gifts of certified ecologically sensitive land expired after five years		–	
Gifts of certified ecologically sensitive land at the beginning of the taxation year		=	
Add: Gifts of certified ecologically sensitive land transferred on amalgamation or wind-up of a subsidiary	+		
Total current year gifts of certified ecologically sensitive land	+		
Subtotal	=	►	
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		–	
Total gifts of certified ecologically sensitive land available		=	
Deduct: Amount applied against taxable income		–	
Gifts of certified ecologically sensitive land closing balance		=	

Part 8 – Analysis of balance by year of origin

Year of origin	Charitable donations	Gifts to Her Majesty in right of Ontario	Gifts to Canada or a province other than Ontario	Gifts of certified cultural property	Gifts of certified ecologically sensitive land
2006-12-31					
2005-12-31					
2005-10-31					
2004-12-31					
2004-05-31					
2003-05-31					
Totals					

Ontario
Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Summary of Dispositions of Capital Property

2005 and later taxation years

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

- **For a corporation that has disposed of capital property or claimed an allowable business investment loss, or both, in the taxation year.**
- **This schedule may be used to make a designation under section 34(10) of the *Corporations Tax Act* provided the corporation has made a designation under paragraph 111(4) (e) of the *Income Tax Act* (Canada), if control of the corporation has been acquired by a person or group of persons.**

Part A: Designation under section 34(10) of the *Corporations Tax Act*

Complete part A if there are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e) of the *Income Tax Act* (Canada) or section 34(10) of the *Corporations Tax Act*.

Property	Class #	Date of disposition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Other adjustments	Designated amount	Gain or loss

Part B: Inter-provincial asset transfers

Complete part B if there was any disposition shown on the schedule as a result of a federal election under section 85 of the *Income Tax Act* (Canada) that transferred assets to a non-arm's length corporation with a permanent establishment in another Canadian jurisdiction.

Property	Class #	Corporation name of transferee/or	Date of disposition YYYY/MM/DD	Cost of asset in other jurisd.	Name of other jurisdiction	Allocation ratio to other jurisdictions	Ontario elected amount	Gain or loss
						%		
						%		
						%		
						%		

Part 1 – Shares

1 Types of capital property: No. of shares	Name of corporation	Class of shares	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)
1								
							Totals	A

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

1 Types of capital property	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)

Part 2 – Real Estate *(Do not include losses on depreciable property)*

	Municipal address	2	3	4	5	6	7
1							

Totals B

Part 3 – Bonds

	Face value	Maturity date YYYY/MM/DD	Name of issuer	2	3	4	5	6	7
1									

Totals C

Part 4 – Other properties *(Do not include losses on depreciable property)*

	Description	2	3	4	5	6	7
1	FIbre property sale			7,708,722	3,206,907	171,258	4,330,557
2							

Totals 4,330,557 D

Part 5 – Personal-use property

	Description of capital property	2	3	4	5	6	7
1							

***Note**: Losses are not deductible*

Net gain or (loss) E

Part 6 – Listed personal property

	Description	2	3	4	5	6	7
1							

Deduct: Unapplied listed personal property losses from other years

***Note:** Net listed personal property losses may only be applied against personal property gains.*

Net gain or (loss) F

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 7 – Property qualifying for and resulting in an allowable business investment loss

	1 Name of small business corporation	Shares – enter 1 Debt – enter 2	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario loss (col. 4 less cols. 5 & 6)
1								
				Totals				
							Net Loss	G

Note: *Properties listed in Part 7 should not be included in any other Part of Schedule 6.*

Allowable business investment loss .... G x 50 % = G1

Transfer to 678 of the CT23 or CT8

Determining capital gains and capital losses

Total of A to F (Do not include F if it is a loss)		4,330,557
Add: Amount (if any) of capital gain reserve opening balance from Schedule 13	+	
Capital gain dividend received in the year	+	
Subtotal	=	4,330,557
Deduct: Amount (if any) of capital gain reserve closing balance from Schedule 13	–	
Gain or Loss (excluding Allowable Business Investment Losses)	=	4,330,557 H

Determining taxable capital gains

Gain or Loss (excluding Allowable Business Investment Losses)				4,330,557 H
Deduct:				
Gain on donations (made to charities other than private foundations) of securities listed on a prescribed stock exchange				
realized prior to May 2, 2006		x 50 %	–	
realized after May 1, 2006			–	
Gain on donation of ecologically sensitive land				
realized prior to May 2, 2006		x 50 %	–	
realized after May 1, 2006			–	
Gains or Loss				4,330,557 I

Include 100% of the losses in box 711 of the CT23 or CT8

Taxable capital gains .... 4,330,557 I x 50 % = 2,165,279 J

Transfer to 603 of the CT23 or CT8

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Is the corporation electing under regulation 1101(5q)? 1 [ ] Yes 2 [X] No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	351,736,287		-928,922	1,327,297	349,480,068		349,480,068	4	0	0	13,979,203	335,500,865
2	78,555,032			0	78,555,032		78,555,032	6	0	0	4,713,302	73,841,730
8	16,225,677	13,609,655		52,202	29,783,130	6,778,727	23,004,403	20	0	0	4,600,881	25,182,249
10	3,453,028	2,291,179		35,903	5,708,304	1,127,638	4,580,666	30	0	0	1,374,200	4,334,104
12	1,121,332	2,834,680		0	3,956,012	1,417,340	2,538,672	100	0	0	2,538,672	1,417,340
17	712,182			0	712,182		712,182	8	0	0	56,975	655,207
42	548,453			838,085	-289,632		-289,632	12	289,632	0		
	29,443,645	10,712,754		0	40,156,399	5,356,377	34,800,022	0	0	0		40,156,399
13	264,569			0	264,569		264,569	N/A	0	0	105,329	159,240
See schedule	23,393,443	42,143,799		1,041,525	64,495,717	20,551,138	43,944,579				4,428,894	60,066,823
Totals	505,453,648	71,592,067	-928,922	3,295,012	572,821,781	35,231,220	537,590,561		289,632		31,797,456	541,313,957

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. 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) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Capital Cost Allowance

Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
13	2,733			0	2,733		2,733	N/A	0	0	2,733	
13	450,350			0	450,350		450,350	N/A	0	0	83,187	367,163
45	1,511,208	1,407,088		0	2,918,296	703,544	2,214,752	45	0	0	996,638	1,921,658
13	149,827			0	149,827		149,827	N/A	0	0	43,854	105,973
13	74,239	9,855		0	84,094	4,928	79,166	N/A	0	0	18,662	65,432
47	21,205,086	40,726,856		1,041,525	60,890,417	19,842,666	41,047,751	8	0	0	3,283,820	57,606,597
Totals	23,393,443	42,143,799		1,041,525	64,495,717	20,551,138	43,944,579				4,428,894	60,066,823

Ontario Ministry of Revenue
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Ontario Cumulative Eligible Capital Deduction

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)*				= + 9,922,135	A
Add: Cost of eligible capital property acquired during the taxation year	+	B			
Other adjustments	+	C			
B + C	=		x 3 / 4 =	D	
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			x 1 / 2 = −	E	
D minus E *(if negative, enter zero)*			=	+	F
Amount transferred on amalgamation or wind-up of subsidiary				+	G
Subtotal A + F + G				= 9,922,135	H
Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+	I			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+	J			
Other adjustments	+	K			
I + J + K	=		x 3 / 4	= −	L
Ontario cumulative eligible capital balance H minus L				= 9,922,135	M

*If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business					N
From **M**	9,922,135				
From **N**					
Current year deduction M minus N	= 9,922,135	x 7 %	= + 694,549		O
N + O			= 694,549	− 694,549	P

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Enter amount in box 651 of the CT23

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)*	= 9,227,586	Q

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.*					R
Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988			+	1	
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA			+	2	
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+	3			
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	−	4			
Deduct line 4 from line 3 *(if negative, enter zero)*	=		+	5	
Total lines 1 + 2 + 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 **1**		7			
Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 (*This will be **Line T** in earlier versions of this schedule.)*	+	8			
Total lines 7 + 8	=		−	9	
Deduct line 9 from line 6 *(if negative, enter zero)*			=		− S
R minus S *(if negative, enter zero)*					= T
From Line **5**	× 1 / 2				= − U
T minus U *(if negative, enter zero)*					= V
From **V**	× 2 / 3				= W
Lesser of **R** and **S**					= + Z
Amount to be included in income W + Z					=

Ontario Ministry of Revenue
Corporations Tax
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Ontario Continuity of Reserves Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

For use by a corporation to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 – Capital gains reserves

Description of property	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
1					
Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 – Other reserves

Description	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from **D** plus the amount from **E** should be entered in 607 of the CT23.
The amount from F should be entered in 654 of the CT23.

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
EMPLOYEE FUTURE BENEFITS	6,321,654		918,910			7,240,564
ALLOWANCE FOR DOUBTFUL ACCTS	850,000					850,000
INVENTORY PROVISION	300,000					300,000
See schedule	703,495		2,411,106			3,114,601
Reserves from Part 2						
Totals	8,175,149		3,330,016			11,505,165
	Enter in box 653 *of the CT23*					*Enter in box* 606 *of the CT23*

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
HOLDBACKS PAYABLE	703,495		1,161,106			1,864,601
Reserves in accruals			490,000			490,000
Donation accrual			760,000			760,000
Totals	703,495		2,411,106			3,114,601

Ontario Ministry of Revenue
Corporations Tax
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PO Box 620
Oshawa ON L1H 8E9

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

This schedule is used to calculate Ontario Scientific Research and Experimental Development Expenditures (SR & ED). The rules used in the calculation of Ontario SR & ED follow the federal rules with the exception of the new Ontario measure introduced in the 2001 Ontario Budget and implemented in Bill 127 which received Royal Assent on December 5, 2001.

This schedule must be completed by all corporations performing qualified Ontario SR & ED in a "specified taxation year" or in the taxation year immediately preceding the first specified taxation year of the corporation and filed with the current CT23 or CT8. Other corporations may use this schedule, if they have claimed or are claiming a different SR & ED amount for Ontario than for federal income tax purposes.

- **"Specified Taxation Year" (STY)** is the taxation year of the corporation that begins after February 29, 2000 **and** ends after December 31, 2000.
- **"Investment Tax Credit Amount" (ITC)** means, in respect of a corporation for a taxation year, an amount deducted by the corporation for a preceding taxation year under subsection 127(5) or (6) of the *Income Tax Act* (Canada) (ITA).
- **"Qualified Ontario SR & ED Expenditure" (QORD)** means,
  - A. A qualified expenditure within the meaning of subsection 12(1) of the *Corporations Tax Act* (CTA) that is made or incurred by a corporation in a STY or in the taxation year immediately preceding the first STY of the corporation, or
  - B. An expenditure made or incurred by a partnership in a fiscal period that ends in a STY of a corporation if,
    - the corporation is member of the partnership at any time in the STY, and
    - the expenditure would be a qualified expenditure within the meaning of subsection 12(1) of the CTA if it were made by a corporation.
- **"Ontario Allocation Factor" (OAF)** has the meaning given to that expression by subsection 12(1) of the CTA.

- If a corporation includes a federal ITC amount in determining the amount of the Ontario pool of deductible SR & ED expenditures for a STY, the following amounts are adjusted by the OAF:
  - Amount of recaptured federal ITC relating to QORD for property disposed of in the preceding taxation year in 442 on page 2.
  - Amount of federal ITC relating to QORD claimed federally in the preceding taxation year(s) in 462 on page 2.
  - Amount of federal ITC relating to QORD allocated from partnerships in the current taxation year in 465 on page 2.

- Federal ITCs earned on shared-use equipment (SUE) reduce the capital cost of the property acquired for federal and Ontario income tax purposes in the taxation year after the taxation year in which the ITC is claimed federally. The amount of the federal ITC that relates to QORD on SUE is added to the SR & ED pool for Ontario purposes in the taxation year after the taxation year in which the ITC is claimed federally.

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Ontario Pool of Deductible SR & ED Expenditures for the current taxation year

Total allowable SR & ED expenditures (capital and current) (From line 400 federal T661 (T2 SCH32))	+	400	1,088,481.
Less: Government and non-government assistance (From line 430 federal T661 (T2 SCH32))	−	430	.
Preceding year's amount of federal ITC claimed for SR & ED (From line 435 federal T661 (T2 SCH32))	−	435	308,961.
Sale of SR & ED capital assets and other deductions (From line 440 federal T661 (T2 SCH32))	−	440	.
Amount of recaptured federal ITC (From line 453 federal T661 (T2 SCH32)) relating to QORD for property disposed of in the preceding taxation year — 442 .			
Gross-up for Ontario allocation factor From 442 . ÷ 100.0000 % (From 30 of the CT23 or CT8)	= −	444	.
Subtotal: 400 − 430 − 435 − 440 − 444	=	445	779,520.
Add: Repayments of government and non-government assistance (From line 445 federal T661 (T2 SCH32))	+	446	.
SR & ED expenditure pool transferred on amalgamation or wind-up (From line 452 federal T661 (T2 SCH32))	+	452	.
Amount of federal ITC recaptured in the preceding taxation year (From line 453 federal T661 (T2 SCH32))	+	453	.
Preceding year's balance in pool of deductible Ontario SR & ED expenditures (From 480 of the preceding taxation year)	+	460	.
Federal ITC relating to QORD **claimed** federally in the preceding taxation year(s) — + 462 308,961. (From 575 on Page 3)			
Amount of federal ITC relating to QORD allocated from partnerships in the current taxation year — + 465 .			
Subtotal 462 + 465 — = 468 308,961.			
Gross-up for Ontario allocation factor From 468 308,961. ÷ 100.0000 % (From 30 of the CT23 or CT8)	= +	470	308,961.
Subtotal: 445 + 446 + 452 + 453 + 460 + 470 (If the amount in 473 is negative, enter zero, in 475, 477 and add 473 to 615 of the 2002 CT23 or CT8 or 616 of the 2003 or later CT23 or CT8. If the amount in 473 is positive, enter the amount in 475.)	=	473	1,088,481.
Amount available for deduction	=	475	1,088,481.
Deduction claimed in the taxation year for Ontario (Enter the SR & ED expenditure pool deduction claimed in the taxation year in 679 of the CT23 or CT8)	−	477	1,088,481.
Ontario current taxation year closing balance in pool of deductible SR & ED expenditures 475 − 477	=	480	.

(Transfer this amount to 460 as the carry forward amount for the next taxation year.)

Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Calculation of Preceding Taxation Year Amount and Account Balances - Federal ITC from SR & ED Expenditures relating to QORD.

- This page is used to calculate the amount of the federal ITC that relates to SR & ED performed in Ontario for certain taxation years and is used to increase the amount of the Ontario SR & ED pool on page 2.
- All amounts on this page are based on the preceding taxation year since the amount of the federal ITC that relates to QORD can only be used to increase the Ontario pool for SR & ED in the current taxation year if there was a federal ITC claimed for federal purposes in the preceding taxation year that related to QORD.
- **Do not include amounts** of federal ITCs that relate to QORD that were **allocated from a partnership.** These amounts are added to your SR & ED pool for Ontario in the taxation year that they are allocated from a partnership to a corporation, not in the year after they are claimed federally.

Opening Balance:	(Enter amount 590 from Schedule 161 of the preceding taxation year, if any)	+	500	
Add:	Amount of federal ITC earned, relating to QORD (QORD portion of line 540 federal T2 SCH31 for the preceding taxation year)	+	510	308,961.
	Amount of federal ITC earned, relating to QORD, transferred on amalgamation or wind-up (QORD portion of line 530 federal T2 SCH31 for the preceding taxation year)	+	520	
Subtotal:	500 + 510 + 520	=	535	308,961.
Deduct:	Amount of federal ITC, relating to QORD, claimed federally (QORD portion of line 560 federal T2 SCH31 for the preceding taxation year)	+	540	308,961.
	Amount of federal ITC, relating to QORD, carried back federally to a preceding taxation year(s) (QORD portion of line P federal T2 SCH31 for the preceding taxation year	+	550	
	A refund of federal ITC, relating to QORD, claimed federally (QORD portion of line 610 federal T2 SCH31 for the preceding taxation year)	+	560	
	Amount of federal ITC, relating to QORD, deemed as a remittance of co-op corporations (QORD portion of line 510 federal T2 SCH31 for the preceding taxation year)	+	570	
Subtotal:	540 + 550 + 560 + 570	=	575	308,961.
				(Transfer this amount to 462 on Page 2)
Deduct:	Amount of federal ITC, relating to QORD, expired per the ITA after 10 taxation years (QORD portion of line 515 federal T2 SCH31 for the preceding taxation year)	−	580	
Closing Balance:	535 − 575 − 580	=	590	
				(Transfer this amount to 500 as the opening balance for the next taxation year.)

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Continuity Schedule for Federal ITC relating to SR & ED Expenditures for the Preceding Taxation Year

- All amounts on this page are based on the preceding taxation year.
- Amounts on this page should tie into Part 12 of federal T2 SCH31 completed for the preceding taxation year.

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions (other than amounts that were allocated from a partnership)	Deductions (only amounts that were allocated from a partnership)	Closing Balance
1998-05-31					
1999-05-31					
2000-05-31					
2001-05-31					
2002-05-31					
2003-05-31					
2004-05-31					
2004-12-31					
2005-10-31					
2005-12-31					
2006-12-31		308,961	308,961		
Totals (see note 1, 2 and 3)	725	740 308,961	755 308,961	770	785

Notes:

1. The amount in 725 should equal the amount of the investment tax credit at the end of the preceding taxation year less line 515 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
2. The amount in 785 should equal the closing balance in line 620 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
3. It is important that the amounts in the deductions columns on this page correctly reflect the year of origin of the federal ITC claimed because only amounts relating to QORD can be used to increase the Ontario SR & ED pool.

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Continuity Schedule for the Amount of Federal ITC from SR & ED Expenditures relating to QORD for the Preceding Taxation Year

- This page is required to record the amount of the ITC that relates to QORD by year of origin.
- All amounts on this page are based on the preceding taxation year.
- **Do not** include amounts of federal ITCs that relate to QORD that were **allocated from a partnership** (see text at the top of page 3).

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions	Closing Balance
2000-05-31				
2001-05-31				
2002-05-31				
2003-05-31				
2004-05-31				
2004-12-31				
2005-10-31				
2005-12-31				
2006-12-31		308,961	308,961	
Totals (see note 1 - 6)	825	840 308,961	855 308,961	870

Notes:

1. The amount in 825 should equal 500 on page 3.
2. The amount in 840 should equal the total of 510 and 520 on page 3.
3. The amount in 855 should equal 575 on page 3.
4. The amount in 870 should equal 590 on page 3.
5. Any deductions that are recorded in the deduction column on this page must be taken out of the same year of origin as indicated in the deduction column on page 4. These deductions must be related to QORD and must not have been allocated from a partnership.
6. The amount of federal ITC relating to QORD will expire if the federal ITC it relates to expires before it is claimed federally.

Ontario Ministry of Revenue
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Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Instructions for completing the CETC Claim Form

- Enter the relevant details for each qualifying work placement, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each qualifying work placement.
- Enter the total tax credit claimed on line 192, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
  - The maximum amount of credit that can be claimed in respect of each work placement is $1,000.
- Ensure you have the following documentation (Do not include with the form or tax return.):
  - a letter of certification from the Ontario college, university other post-secondary institution, containing information as specified by the Minister, stating that the student is enrolled in a qualifying education program; or
  - a voucher for leading-edge technology programs, other than an apprenticeship, stating that the educational program meets the definition of a qualifying program in leading-edge technology and that the work performed by that student during the work placement is in a related field.
- The credit is **considered government assistance** and is therefore **to be included in income** in the year the credit is claimed.

Summary of Co-operative Education Tax Credit Claimed

Complete a separate entry for each student work placement which ended during the corporation's taxation year. The tax credit is for co-op work placements and leading-edge technology work placements. A work placement is generally considered to be a full-time work assignment for up to 4 months in duration.

Example: If a corporation, with a December 31, 2001 taxation year end, hires an eligible student from September 1, 2001 until April 30, 2002, this would be considered 2 work placements. The first work placement is September 1, 2001 to December 31, 2001 and would be claimed in the 2001 taxation year. The second placement is January 1, 2002 to April 30, 2002 and must be claimed in the 2002 taxation year.

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates (year month day)	Eligible Costs of Placement (ECP)	* Credit Claimed (See notes below) (max. $1,000 per work placement)
University of Windsor	Ranjeeta Jhaveri		From 2007-01-03 To 2007-12-31	37,464	17,000
University of Windsor	Vic Kalchev		From 2007-05-02 To 2007-12-31	23,552	1,000
See schedule			From To	182,392	16,956
If insufficient space, attach schedule			**Totals**	5774 243,408	5798 34,956

Transfer to 192 ***on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8***

Note: Enter corporation's salaries & wages paid in the preceding taxation year **A** $ 22,769,148 •

If **A** is $600,000 or greater use 10%. If A is $400,000 or less use 15%.

If **A** is over $400,000 but less than $600,000 use the following formula to calculate the rate:

Rate = .15 – [.05 (From **A** 22,769,148 • – $400,000) ÷ $200,000]

Indicate rate used: 10.0000 %. ***Credit claimed equals ECP multiplied by rate.**

Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates (year month day)	Eligible Costs of Placement (ECP)	Credit Claimed (max. $1,000 per work placement)
Georgian College	Derick Kent		From 2007-01-04 To 2007-12-31	15,150	1,000
Georgian College	Jason Greenfield		From 2007-01-17 To 2007-12-31	15,064	1,000
Georgian College	Amanda McLeod		From 2007-05-07 To 2007-08-24	12,234	1,000
University of Guelph	Jennifer Rideout		From 2007-01-08 To 2007-08-03	10,217	1,000
McMaster University	Daniel Lai		From 2007-01-02 To 2007-04-20	10,167	1,000
University of Waterloo	Soo Park		From 2007-05-17 To 2007-09-06	9,644	964
Georgian College	Ken Parks		From 2007-04-30 To 2007-12-31	9,604	960
Georgian College	Dan Turcu		From 2006-12-18 To 2007-05-07	8,175	818
Ryerson University	Jenny Fong		From 2007-04-30 To 2007-08-31	8,050	805
Seneca College	Stanislavs Motovs		From 2006-08-29 To 2007-05-04	7,566	757
Georgian College	James Harrington		From 2007-05-04 To 2007-12-31	7,523	752

Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates (year month day)	Eligible Costs of Placement (ECP)	Credit Claimed (max. $1,000 per work placement)
Georgian College	Blair Armstrong		From 2007-05-07 To 2007-08-31	7,491	749
Centennial College	Hussein Abdulali		From 2007-04-30 To 2007-08-31	7,431	743
Ryerson University	Jason Wu		From 2007-05-07 To 2007-08-29	7,401	740
Georgian College	Nick Cranch		From 2007-01-08 To 2007-04-30	7,240	724
Georgian College	Josh Urbanski		From 2007-08-27 To 2007-12-31	6,653	665
Georgian College	Ivy Li		From 2006-12-18 To 2007-04-27	6,548	655
Ryerson University	Jason McBurney		From 2007-09-10 To 2007-12-31	6,279	628
Georgian College	Daniel Salb		From 2007-09-10 To 2007-12-14	6,219	622
Georgian College	Dan Poulin		From 2007-09-04 To 2007-12-31	6,118	612
Georgian College	D'Arcy McKinnon		From 2007-09-04 To 2007-12-31	7,618	762
			From To		

Totals	182,392	16,956

Corporate Taxpayer Summary

Corporate information

Corporation's name	POWERSTREAM INC.
Taxation Year	2007-01-01 to 2007-12-31
Jurisdiction	Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

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*	-632,413

* 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	35,400,459
Taxable income	35,294,289
Donations	106,170
Calculation of income from an active business carried on in Canada	33,235,180
Dividends paid	4,736,400
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	37,159,280
Balance of the general rate income pool at the end of the year	59,687,007
Part I tax (base amount)	13,411,830
Surtax	395,296

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	7,810,382	ITC refund	
M&P deduction		Part I.3		Dividends refund	577,408
Foreign tax credit		Part IV		Instalments	7,232,974
Political contributions	558	Part III.1		Surtax credit	
Investment tax credits	292,078	Other*		Other*	
Abatement/Other*	5,848,460	Provincial or territorial tax			
				Balance due/refund (–)	

* 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

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	
Capital dividend amount	2,587,166
Part I tax credit (Schedule 42)	
Cumulative eligible capital	9,227,586
Capital gains reserves	
Financial statement reserve	11,505,165
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	Québec (CO-17)	Alberta (AT1)
Net income	35,091,498		
Taxable income	34,985,328		
% Allocation	100.00		
Attributed taxable income	34,985,328		
Surtax	34,000	N/A	N/A
Tax payable before deduction*	4,897,946		
Deductions and credits	121,916		
Net tax payable	4,810,030		
Attributed taxable capital	535,601,747		N/A
Capital tax payable**	1,490,840		N/A
Total tax payable***	6,300,870		
Instalments and refundable credits	6,933,283		
Balance due/Refund (-)	-632,413		

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable			
Instalments and refundable credits			
Balance due/Refund (-)			

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses			
Net capital/L.P.P. losses			
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves	11,505,165	11,505,165	11,505,165
Other reserves			
Eligible capital	9,227,586	9,227,586	9,227,586

Other carryforward amounts

Ontario	
Continuity of other eligible CMT losses – Filling Corporation – OCMT101	
Predecessor corporations only – Amalgamation – OCMT101	
Predecessor corporations only – Wind-up – OCMT101	
CMT credit carryovers workchart – Filling Corporation – OCMT101	
CMT credit carryovers workchart – Predecessor corporations only – Amalgamation	
CMT credit carryovers workchart – Wind-up – OCMT101	
Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161	
Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161	
Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year – O161	
Québec	
R&D expenditures not deducted at the end of the year – RD-222	
Foreign non-business income tax credits – CO-17S.39	
Development work expenses – FM220.3	
Excess development work expenses – FM220.3	
Balance of patronage dividends – CO-786	
Alberta	
Unclaimed SR&ED expenditure pool deduction balance – A16	
British Columbia	
Scientific research and experimental development – Schedule 425	
Manufacturing and processing – Schedule 426	
Manitoba	
Research and development – Schedule 380	
Manufacturing investment – Schedule 381	
Co-operative education – Schedule 384	
Odour control – Schedule 385	
Saskatchewan	
Manufacturing and processing investment – Schedule 402	
Research and development – Schedule 403	
Newfoundland and Labrador	
Direct equity tax – Schedule 303	
Prince Edward Island	
Investment – Schedule 321	
Nova Scotia	
Energy efficiency tax credit – Schedule 342	
Manufacturing and processing investment – Schedule 344	
New Brunswick	
Research and development – Schedule 360	
Nunavut	
Investment – Schedule 480	

Five Year Comparative Summary

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Federal information (T2)					
Taxation year end	**2007-12-31**	**2006-12-31**	**2005-12-31**	**2005-10-31**	**2004-12-31**
Net income	35,400,459	31,432,728	1,878,510	22,668,320	13,739,321
Taxable income	35,294,289	31,384,069	1,861,125	22,660,800	13,727,321
Active business income	33,235,180	31,121,818	1,878,510	22,668,320	13,628,343
Dividends paid	4,736,400	6,555,000		6,800,000	900,000
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	37,159,280				
GRIP – end of the year	59,687,007	37,159,280			
Donations	106,170	48,659	17,385	7,520	
Balance due/refund (-)				-399,339	

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Federal taxes					
Part I before surtax	7,415,086	11,925,946	390,836	4,758,118	2,897,905
Surtax	395,296	351,502	20,845	253,801	153,746
Part I.3			107,600	440,436	376,075
Part IV					
Part I & Surtax	7,810,382	6,983,997	411,681	5,011,919	
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Credits against part I tax					
Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution	558	650		650	
Investment tax credit	292,078				
Abatement/other*	5,848,460	5,313,528	316,392	3,852,336	1,372,732

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Refunds/credits					
ITC refund					
Dividend refund	577,408	113,837			29,638
Instalments	7,232,974	6,870,160	519,281	5,851,694	3,398,088
Surtax credit			20,845	253,801	
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario (CT-23)

Taxation year end	2007-12-31	2006-12-31	2005-12-31	2005-10-31	2004-12-31
Net income	35,091,498				
Taxable income	34,985,328				
% Allocation	100.00				
Attributed taxable income	34,985,328	31,354,156	1,861,125	22,660,800	13,720,450
Surtax	34,000	34,000			
Income tax payable before deduction	4,897,946	4,389,582	260,558	3,172,512	1,920,863
Income tax deductions /credits	121,916	70,108	3,060	1,000	4,266
Net income tax payable	4,810,030	4,353,474	257,498	3,171,512	1,916,597
Taxable capital	535,601,747	496,012,385	484,408,978	569,265,351	495,031,050
Capital tax payable	1,490,840	1,458,037	239,108		859,563
Total tax payable*	6,300,870	5,811,511	496,606	3,171,512	2,776,160
Instalments and refundable credits	6,933,283	5,490,913	70,052	4,919,784	
Balance due/refund	-632,413	320,598	426,554	-1,748,272	-1,742,284

* This includes corporate minimum tax and premium tax.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2008-12-31

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
2008-01-31	650,866			650,866
2008-02-29	650,866			650,866
2008-03-31	650,866			650,866
2008-04-30	650,866			650,866
2008-05-31	650,866			650,866
2008-06-30	650,866			650,866
2008-07-31	650,866			650,866
2008-08-31	650,866			650,866
2008-09-30	650,866			650,866
2008-10-31	650,866			650,866
2008-11-30	650,866			650,866
2008-12-31	650,856			650,856
Total	7,810,382			7,810,382

Ontario Tax Instalments

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Ontario tax instalments

For the taxation year ended: 2008-12-31

The following is a list of Ontario instalments payable for the current taxation year. The last column indicates the instalments payable to the Ontario Ministry of Revenue. 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 Minister of Revenue. Payment may be made either to a chartered bank in Ontario or filed with an instalment form and addressed to:

Ministry of Revenue (Ontario)
Corporation Tax
33 King Street West
P.O. Box 620
Oshawa Ontario
L1H 8E9

Quarterly instalment

Date	Instalments required	Instalments paid	Cumulative difference	Instalments payable
Total				

Date	Instalments required	Instalments paid	Cumulative difference	Instalments payable
2008-01-31	525,073			525,073
2008-02-29	525,073			525,073
2008-03-31	525,073			525,073
2008-04-30	525,073			525,073
2008-05-31	525,073			525,073
2008-06-30	525,073			525,073
2008-07-31	525,073			525,073
2008-08-31	525,073			525,073
2008-09-30	525,073			525,073
2008-10-31	525,073			525,073
2008-11-30	525,073			525,073
2008-12-31	525,067			525,067
Total	6,300,870			6,300,870

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Apprenticeship Training Tax Credit (ATTC)

CT23 Schedule 114

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Instructions for completing the ATTC Claim Form

- Enter the relevant details for each eligible apprentice, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each eligible apprentice.
- Enter the total tax credit claimed on line 203, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Enter the total number of apprentices hired on line 202, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Corporations are eligible for a 25% (30% in the case of corporations with payroll not exceeding $400,000) refundable tax credit on wages and salaries paid or payable for services performed after May 18, 2004 by an eligible apprentice during the first 36 months of an apprenticeship.
- The maximum amount of credit that can be claimed in respect of each eligible apprentice is $5,000 per year to a maximum of $15,000 over the first 36 months of the apprenticeship. The maximum annual tax credit of $5,000 is pro-rated for the number of days the apprentice was employed during the taxation year.
- The credit is *considered government assistance* and is therefore *to be included in income* in the year the credit is claimed.

Summary of Apprenticeship Training Tax Credit Claimed

Complete a separate entry for each eligible apprentice that is in a qualifying skilled trade and hired before January 1, 2008. This credit applies to **salaries and wages paid after May 18, 2004 and before January 1, 2011** to eligible apprentices during the first 36 months of an apprenticeship.

Example: A taxpayer, with a December 31, 2004 taxation year end, hires an otherwise eligible apprentice on June 1, 2004 at a salary of $3,500 per month. The taxpayer's salaries and wages in the preceding taxation year were $700,000. The credit claimed is the lesser of *(1) 25% of salaries paid to the apprentice during the period of employment (25% x $3,500 x 7 = $6,125), and *(2) $5,000 multiplied by the number of days the apprentice was employed during the taxation year, divided by the total number of days in the calendar year ($5,000 x 214/366 = $2,923). Hence, the credit claimed in the 2004 taxation year is $2,923.

Eligible Apprenticeship

Trade Code	Description of Apprenticeship Program	Apprentice Name and Social Insurance No. (SIN)	Registration Date of Apprenticeship Contract or Training Agreement year month day	Contract or Agreement No.	Employment Period year month day	Eligible Expenditures (EE)	* Credit Claimed (see notes below)
434a	Lineworker	Name Michael Wilmot SIN 493 313 720	2006-02-27	15004	From 2007-01-01 To 2007-12-31	62,813	5,000
434a	Lineworker	Name Ryan Walsh SIN 494 406 309	2006-02-27	15003	From 2007-01-01 To 2007-12-31	65,953	5,000
	See schedule					475,134	42,960
					Totals	5874 603,900	5898 52,960

If insufficient space, attach schedule

Transfer to 203 on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8

Corporation's salaries & wages paid in the preceding taxation year A $ 22,769,148 •

- If A is $600,000 or greater use 25%.
- If A is $400,000 or less use 30%.
- If A is over $400,000 but less than $600,000 use the following formula to calculate the specified percentage:

Specified percentage = .30 − [.05 (From A 22,769,148 • − $400,000) ÷ $200,000]

Indicated specified percentage used 25.0000 %

*** Credit claimed equals lesser of:**

(1) EE multiplied by the specified percentage, and

(2) $5,000 x number of days the apprentice was employed in the taxation year / 365 (366 if leap year)

Total Number of Apprentices . . . . = 5896 12 •

Transfer to 202 on Page 7 of the CT23 Long or Page 4 of the CT23 Short, or Page 4 of the CT8

Apprenticeship Training Tax Credit (ATTC)

CT23 Schedule 114

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Eligible Apprenticeship

Trade Code	Description of Apprenticeship Program	Apprentice Name and Social Insurance No. (SIN)	Registration Date of Apprenticeship Contract or Training Agreement year month day	Contract or Agreement No.	Employment Period year month day	Eligible Expenditures (EE)	* Credit Claimed (see notes below)
434a	Lineworker	Name Cory Holmes SIN 476 271 424	2006-02-27	15005	From 2007-01-01 To 2007-12-31	57,705	5,000
434a	Lineworker	Name Matthew Cousins SIN 520 656 505	2007-06-07	23969	From 2007-03-21 To 2007-12-31	36,784	3,918
434a	Lineworker	Name Jeff Long SIN 530 376 334	2007-06-07	23970	From 2007-03-21 To 2007-12-31	39,772	3,918
434a	Lineworker	Name Adam Maas SIN 522 131 747	2007-06-07	23971	From 2007-03-21 To 2007-12-31	35,624	3,918
434a	Lineworker	Name Steven Robinson SIN 488 459 827	2007-06-07	23972	From 2007-03-21 To 2007-12-31	39,319	3,918
434a	Lineworker	Name Tim Lamb SIN 513 947 713	2007-06-07	23973	From 2007-04-10 To 2007-12-31	36,113	3,644
434a	Lineworker	Name Bob Hellings SIN 526 305 602	2005-02-21	1918350	From 2007-04-10 To 2007-12-31	43,643	3,644
434a	Lineworker	Name Christopher Simpson SIN 511 668 410	2006-02-27	15006	From 2007-01-01 To 2007-12-31	61,452	5,000
434a	Lineworker	Name Rob Chard SIN 512 274 291	2006-02-27	15007	From 2007-01-01 To 2007-12-31	56,331	5,000
434a	Lineworker	Name Christopher Hagan SIN 514 633 064	2006-02-27	15002	From 2007-01-01 To 2007-12-31	68,391	5,000
					Totals	475,134	42,960

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Innovation Tax Credit (OITC) Claim

This form is valid for 2005 and subsequent taxation years.

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

	Yes	No
Was the corporation eligible to claim federal investment tax credit with respect to the qualified expenditures incurred in the taxation year?	X	
Did the corporation have a permanent establishment in Ontario for the period covered by this claim?	X	
Did the corporation file a federal SR&ED claim Form T661? *If yes, please attach a copy of Form T661 and schedule T2 SCH 31.*	X	
Was the corporation a member of an associated group during the taxation year? *If yes, please attach a copy of schedule T2 SCH 23 and T2 SCH 49.*		X
Percentage of corporation's SR&ED carried on in Ontario	100 %	
Have contract or third party payments been paid/payable in respect of any of the qualifying expenditures being claimed for this OITC? *If yes, please complete Part 3 of this form.*		X

Part 1 - Calculation of the Ontario Innovation Tax Credit

		Taxable Income		Part 1.3 Tax (credit unions and insurance corporations)
Corporation's Federal Taxable Income in preceding taxation year (if short fiscal, gross up taxable income in accordance with fed.s.127(10.6))	+ 5000	31,384,069		
Corporation's Federal Part 1.3 Tax in preceding taxation year (if short fiscal, tax is grossed up in accordance with fed.s.125(5.1))			+ 5025	

Add: (if associated) Federal Taxable Income(s) (grossed up) and Federal Part 1.3 Tax (Part 1.3 Tax before the impact of fed.s.181.1(2)&(4)) in preceding taxation year(s) of associated corporation(s)

Name(s) of associated corporation(s) *(if insufficient space, attach schedule)*	Corporations Tax Number(s) *(if applicable)*	Taxation Year End(s)				
			+		+	
			+		+	
			+		+	

Total Federal Taxable Income of the corporation and associated corporation(s) 5000 + 5002 + 5004 + 5006 . . . . = 5020 31,384,069

Total Federal Part 1.3 Tax of the corporation and associated corporation(s) 5025 + 5027 + 5029 + 5031 . . . . = 5040

Ontario Innovation Tax Credit (OITC) Claim

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

1. Qualifying Expenditure Limit

Complete 1(a)(i) to 1(a)(v). Transfer amount calculated for 5071 to 5120 on page 3, and proceed to section 2: *Qualifying Expenditures in Taxation Year.* Complete Part 2 if non-CCPC.

1(a) Phase out of $2,000,000 Expenditure Limit if federal taxable income of preceding taxation year exceeds $300,000 ($400,000 if preceding taxation year ends after 2006) and/or taxable capital exceeds $25,000,000. If taxable capital in line 5066 equals or exceeds $50,000,000, enter zero in line 5071 .

1(a)(i) Determination of Business Limit in the current taxation year pursuant to subsection 41(3.1) of the *Corporations Tax Act*

Corporation's business limit for the current taxation year
(For CCPC: Line 410 from page 4 of the T2 or amount allocated from federal Sch. 23)
(For non-CCPC: Line 410 from Part 2 of the OITC Claim form) . . . . . + 5044 400,000

Add: (if associated) business limit of associated corporation(s)

Name(s) of associated corporation(s)	Corporation Tax Number(s)	Taxation Year End(s)		Business Limit (line 410 from T2 or Part 2)
			+	
			+	
			+	

Total business limit 5044 + 5045 + 5046 + 5047 . . . . . = 5058 400,000

1(a)(ii) Determination of Maximum Business Limit in the current taxation year

Corporation's maximum business limit for the current taxation year
(For CCPC: Line 4 from page 4 of the T2)
(For non-CCPC: Line 4 from Part 2 of the OITC Claim form) . . . . . + 5701 400,000

Add: (if associated) maximum business limit of associated corporation(s)

Name(s) of associated corporation(s)	Corporation Tax Number(s)	Taxation Year End(s)		Maximum Business Limit allocated from fed. Sch. 23 or Part 2
			+	
			+	
			+	

Total maximum business limit 5701 + 5702 + 5703 + 5704 . . . . . = 5705 400,000
(For CCPC: equal to total **A** in column 6 of fed. Sch. 23)
(For non-CCPC: equal to total **A** in Part 2 of the OITC Claim form)

1(a)(iii) Proration of Small Business Limit based on Taxable Paid-up Capital in the preceding taxation year

Corporation's taxable paid-up capital in the preceding taxation year **(Note 1)** . . . . . + 5061 496,012,385

Add: (if associated) taxable paid-up capital in the preceding taxation year of associated corporation(s) **(Note 1)**

Name(s) of associated corporation(s)	Corporation Tax Number(s)	Taxation Year End(s)		Taxable Paid-up Capital
			+	
			+	
			+	

Total Taxable Paid-up Capital 5061 + 5062 + 5063 + 5064 . . . . . = 5066 496,012,385

Deduct: . . . . . − $ 25,000,000

Excess capital amounts *(If the amount is negative, enter zero)* . . . . . = 5068 471,012,385

Note 1

- Use **Ontario** adjusted taxable paid-up capital for the preceding taxation year, if the corporation is a financial institution other than a credit union or an insurance corporation.
- Use **federal** taxable capital employed for the preceding taxation year as determined under part 1.3 of the *Income Tax Act* (Canada), if the corporation is a credit union or an insurance corporation.
- Use **Ontario** taxable paid-up capital for the preceding taxation year for all other corporations.

Ontario Innovation Tax Credit (OITC) Claim

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

1(a)(iv) Proration of Small Business Limit

From 5058 Business Limit 400,000 – (From 5058 Business Limit 400,000 X From 5068 471,012,385 ÷ $ 25,000,000) = 5069

1(a)(v) Determination of qualifying Expenditure Limit

(* $ 5,000,000 – 10 X The greater of 5020 or *$400,000 31,384,069) X From 5069 ÷ From 5705 400,000 = 5071

Transfer to 5120

* If your taxation year ended before 2007, the references to $6,000,000 and $400,000 should be $5,000,000 and $300,000 respectively.

1(b) Allocation of Expenditure Limit (lesser of $2,000,000 or 5071) to corporation and associated corporations.

Name of corporation		Expenditure Limit
POWERSTREAM INC.	+ 5080	
Name(s) of associated corporation(s)		
	+	
	+	
	+	
Total Expenditure Limit (Lesser of $2,000,000 or 5071)	= 5120	

2. Qualifying Expenditures in Taxation Year

		Expenditures		Allowable Portion			
Current Expenditures	+ 5130	1,460,391	+ 5160		x	100 %	= + 5190
Capital Expenditures	+ 5140		+ 5170		x	40 %	= + 5200
Total Qualifying Expenditures	= 5150	1,460,391	= 5180				= 5210

If 5150 is less than or equal to 5080 above, transfer amounts from 5130 and 5140 to 5160 and 5170 respectively.

If 5150 is greater than 5080 , reduce amounts in 5130 and 5140 in order that the sum 5130 and 5140 is equal to 5080 and transfer adjusted amounts to 5160 and 5170 respectively.

3. Calculation of Tax Credit

Amount eligible for OITC From 5210 x 10 % . . . . = 5250

Transfer to Summary, page 5

Part 2 - Business Limit Calculation for Non-Canadian-Controlled Private Corporations (Non-CCPCs)

Calculation of the business limit:

For all non-CCPCs, calculate the amount at line 4 below. If necessary, attach additional business limit calculation for each associated group member.

250,000 X $\frac{\text{Number of days in the taxation year in 2004}}{\text{Number of days in the taxation year}}$ = 1

300,000 X $\frac{\text{Number of days in the taxation year in 2005 and in 2006}}{\text{Number of days in the taxation year}}$ = 2

400,000 X $\frac{\text{Number of days in the taxation year after 2006}}{\text{Number of days in the taxation year}}$ = 3 400,000

Add amounts at lines **1**, **2** and **3** . . . . = 4 400,000

Business Limit (see note 2 below) 410 400,000

Transfer to 5044

Note 2
- For non-CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's taxation year is less than 51 weeks, prorate the amount from line 4 by the number of days in the taxation year divided by 365, and enter the result on line 410.
- For associated non-CCPCs, use the schedule (Allocating the business limit) on page 4 to calculate the amount to be entered on line 410.

Ontario Innovation Tax Credit (OITC) Claim

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Allocating the business limit

Calendar year to which the allocation agreement applies 2007

Column 3: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 3 of each respective non-CCPC's schedule; it is computed at line 4 on page 4 of each respective CCPC's T2 return.

Column 5: Enter the business limit allocated to each corporation by multiplying the amount in column 3 by the percentage in column 4. Add all business limits allocated in column 5 and enter the total at line **A**. Ensure that the total at line **A** falls within the range for the calendar year to which the allocation agreement applies:

Calendar year	Acceptable range
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line **A** does not exceed $400,000.

1 Names of associated corporations	2 Business Number of associated corporations	3 Business limit for the year (before the allocation) $	4 Percentage of the business limit (the total of all percentages cannot exceed 100%)	5 * Business limit allocated $
POWERSTREAM INC.	85750 3346 RC0002	400,000	100.0000	400,000
			Total	**A** 400,000

Transfer to 5705

* Each non-CCPC will enter on line 410 on page 3, the amount allocated to it in column 5. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 5 by the number of days in the tax year divided by 365, and enter the result on line 410 on page 3.

Special rules apply if a qualifying corporation has more than one tax year ending in a calendar year and is associated in more than one of those years with another qualifying corporation that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

Part 3 - Contract Payments

Generally, contract payments received from another corporation are ineligible for SR&ED incentives. Such payments, if eligible, would be claimed by the corporation making the payment. However, OITC legislation provides for **specified contract payments**. This legislation permits an otherwise ineligible payment to be considered eligible (by the recipient), as a **specified contract payment** if the following conditions are met:

a) The payment is a contract payment for the performance of SR&ED carried on in Ontario.

b) The corporation making the payment (the payor):

i) does not have a permanent establishment in Ontario, and

ii) is not otherwise eligible for either the Ontario Super Allowance or the OITC.

Details of SR&ED performed under contract for which the OITC is being claimed

Name and address of corporation making the payment	Is payment a specified contract payment? Yes	No	Is this an arms-length transaction? Yes	No	Gross amount of contract payment	Actual SR&ED expenditure relating to contract included in claim

Ontario Innovation Tax Credit (OITC) Claim

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
POWERSTREAM INC.	1800391	2007-12-31

Part 4 - Third-Party Payments

Details of payments made to approved universities, research institutions, or other eligible SR&ED performers for which the OITC is being claimed

Name and address of performer of the eligible SR&ED	Was all the work performed in Ontario? Yes No	Is this an arms-length Transaction? Yes No	Amount of third-party payment included in this claim

Part 5 - OITC Waiver

If a corporation waives its eligibility for all or part of the tax credit, it is deemed to never have been a qualifying corporation for that year in respect of the amount of the tax credit that it waived.

Eligible OITC before waiver . . . . From 5250

Deduct: Amount of OITC waived . . . . − 5610

Amount of OITC claim . . . . = 5620

Transfer to Summary

I understand that by signing this waiver the corporation forfeits its eligibility to claim the tax credit under the *Corporations Tax Act* with respect to the amount of the OITC entered in 5610.

Signature of authorized signing officer	Date
	2008-06-26

Part 6 - Summary OITC Claim

Ontario Innovation Tax Credit . . . . From 5250

Deduct: OITC waived . . . . − From 5610

Ontario Innovation Tax Credit Claimed 5250 − 5610 . . . . = 5620

Transfer to 191 *of the CT23 or CT8*

Part 7 - Certification

I am an authorized signing officer of the corporation. I certify that this Ontario Innovation Tax Credit Claim form has been examined by me and is true, correct and complete and that the information provided in this claim is in agreement with the books and records of the corporation.

Name of authorized signing officer	Title	Signature	Date
LUCY LOMBARDI	DIRECTOR, CORPORATE FINANCE		2008-06-26