Ottawa River Power Corporation

2010 EDR Application

EB-2009-0165

Submitted 30 June, 2010

Ottawa River Power Corporation
283 Pembroke Street West
Pembroke, ON K8A 6Y6
Douglas Fee 613.732.3687

Exhibit 1:

ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

Tab 1 (of 4): Application Summary

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LEGAL APPLICATION

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Ottawa River Power Corporation for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2010 distribution rates and related matters.

APPLICATION

1) The Applicant is Ottawa River Power Corporation (“ORPC”). ORPC is a licensed electricity distributor operating pursuant to license ED-2003-0033. The urban communities served by ORPC are limited to the City of Pembroke, the Township of Whitewater (Beachburg only), the Town of Mississippi Mills (Almonte Ward only) and the Township of Killaloe, Haggarty & Richards (Killaloe only). ORPC has no special conditions in its’ license. ORPC is an embedded distributor; adjacent distributors are Hydro One Inc. and Hydro Quebec

2) ORPC hereby applies to the Ontario Energy Board (the "Board") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended, (the "OEB Act") approving just and reasonable rates for the distribution of electricity based on a 2010 test year.

3) Specifically, ORPC hereby applies for an order or orders granting approval of:

    a) its forecasted 2010 distribution revenue requirement of $3,972,542;

    b) distribution rates that allow ORPC to recover its forecasted 2010 distribution revenue requirement, effective May 1, 2010;

c) other regulated income of $377.968;

d) the disposition of Regulatory Asset, deferral and variance accounts;

e) ORPC's current distribution rates being deemed interim commencing May 1, 2010 until its proposed distribution rates are implemented; and

f) other approvals as set out in Exhibit 1, Tab 1, Schedule 3.

4) As indicated by ORPC's pre-filed evidence, its proposed 2010 revenue requirement is $4,350,510. Based on current distribution rates and forecasted load, ORPC projects a revenue deficiency of $417,801.

5) The 2010 rates proposed by ORPC will result in overall monthly bill impacts as follows: a) a Residential customer using 800 kWh's in the summer - a 12.0% decrease; b) a General Service customer less than 50 kW using 2,000 kWh's - a 7.3% decrease; c) a General Service customer 50 to 4,999 kW with a demand of 120 kW and energy of 45,900 kWh's – a 9.3% decrease; d) Unmetered Scattered Load using 500 kWh's – a 37.8% decrease; e) Sentinel Lighting with a demand of 0.29 kW and energy of 102 kWh – a 2.6% increase; and f) Street Lighting with a demand of 0.22 kW's and energy of 76 kWh's – an 8.6% increase.

6) This Application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated May 27, 2009.

7) This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

8) The Applicant requests that, pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

9) The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's advisor, as follows:

The Applicant:

Ottawa River Power Corporation.
283 Pembroke St. West
PO Box 1087
Pembroke, ON K8A 6Y6

Attention:
Douglas Fee
dfee@orpowercorp.com
Tel: 613-732-3687
Fax: 613.732.8199

Jane Wilkinson
jwilkinson@orpowercorp.com
Tel: 613-732-3687 ext. 34
Fax: 613.732.8199

The Applicant's advisor:

Elenchus Research Associates
34 King Street East, Suite 600
Toronto, Ontario M5C 2X8

Attention:
James Cochrane
jcochrane@elenchus.ca
Telephone: (416) 710-2704
Fax: (416) 348-9930

DATED at Pembroke, Ontario, this 30th day of June, 2010.

OTTAWA RIVER POWER CORPORATION

Douglas Fee

President

SUMMARY OF APPLICATION AND APPROVALS REQUESTED

ORPC is submitting this application for rates that are just and reasonable. The current rates will result in actual a Return on Equity in 2010 below the level currently approved by the OEB. The increase in rates is required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.

2) Manage staffing levels and skills to ensure regulatory compliance, ESA compliance, promote conservation programs, implementation of smart meters, prepare for the Green Energy and Green Economy Act requirements, and implement changes required from the adoption of International Financial Reporting Standards.

3) Pursue ORPC's top priority for the health and safety of its workers.

4) Provide a reasonable rate of return to shareholders.

ORPC has consistently met or exceeded the OEB's Service Quality Indicators, and continues to review and monitor its progress to ensure these targets are met or exceeded on a regular basis in 2010.

In this proceeding, ORPC is seeking the following approvals:

- Approval to charge rates effective May 1, 2010 to recover a revenue requirement of $4,350,510, as set out in Exhibit 6, Tab 1, Schedule 2 and Exhibit 6, Tab 2, Schedule 1.

- Approval of proposed rates as set out in Exhibit 8, Tab 4, Schedule 4, Attachment 1.

- Approval of the proposed capital structure, with a deemed common equity component of 40% and a deemed debt component of 60%, as set out in Exhibit 5, Tab 1, Schedule 1 consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.

- Approval of the proposed loss factor as set out in Exhibit 8, Tab 3, Schedule 3, Attachment 1.

- Approval to continue to charge Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of ORPC's 2009 Distribution Rates (EB-2008-0206).

- Approval of the proposed change to the Wholesale Market Service rate as set out in Exhibit 8, Tab 3, Schedule 4.

- Approval of the Retail Transmission – Network Service and Retail Transmission – Connection rates, in accordance with the Guideline for Electricity Distribution Retail Transmission Service (G-2008-0001), Revision 1.0 issued July 22, 2009.

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of ORPC's 2009 Distribution Rates (EB-2008-0206).

- Approval to record actual Provincial Sales Tax amounts paid in the first six months of 2010 to a deferral account for future recovery. ORPC's test year spending projections exclude any sales taxes, given the implementation of the Harmonized Sales Tax on July 1, 2010.

- Approval to dispose of Deferral and Variance Account balances as at December 31, 2009 with interest to April 30, 2010, over a four-year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 1, Attachment 1.

- Approval to dispose of the 1588-RSVA/Power variance account, sub-account Global Adjustment, by way of a distinct rate rider charged to customers not subject to the Regulated Price Plan, as calculated in Exhibit 8, Tab 2, Schedule 2, Attachment 1.

- Approval to use the Board Approved 1595 account – Disposition and Recovery of Regulatory Balances and sub-accounts to record the disposition and recoveries of Deferral and Variance account balances.

- Approval to use the Board Approved accounts to collect costs in connection with the Green Energy and Green Economy Act (GEGEA) described as:

  - 1531 – Renewable Connection Capital Deferral Account
  - 1532 – Renewable Connection OM&A Deferral Account
  - 1534 – Smart Grid Capital Deferral Account
  - 1535 – Smart Grid OM&A Deferral Account

- Approval for a Smart Meter Adder of $1.54 per month per metered customer, based on the cost analysis and deployment plan presented in Exhibit 9, Tab 3.

Attachment 1 (of 1):

Procedural Orders. Motions & Correspondence

Attached is a letter from the Board dated April 20, 2010, advising ORPC that any application for 2010 rates filed after April 30, 2010 should be filed on the basis of the 2nd generation incentive regulation mechanism. ORPC's reply, requesting an extension until June 30, 2010 to submit a cost of service application, is also attached.

To date, ORPC has not received a reply from the Board to its request. For the reasons stated in its letter, ORPC respectfully requests the Board accept the filing of this application.

As at the date of submitting this application, ORPC has not been served with any other utility-specific Procedural Orders, Motions or Correspondence on any matters which relate, directly or indirectly, to its application for 2010 rates.

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

VIA E-MAIL

April 20, 2010

Douglas Fee
President & C.E.O.
Ottawa River Power Corporation
283 Pembroke Street West
Pembroke ON K8A 6Y6

Dear Mr. Fee:

RE: Application for Rates for the 2010 Rate Year
Direction Regarding Filing

By letter dated March 5, 2009, all licensed electricity distributors were advised that cost of service rate applications should be filed no later than August 28, 2009 for rates to be effective May 1, 2010.

To date, the Board has not received your cost of service rate application for the 2010 rate year. The 2010 rate year is intended to cover the period May 1, 2010 to April 30, 2011. Cost of service applications are assessed on a future test year basis, and the Board therefore expects that these filings be made substantially before the beginning of the rate year. In addition, a rate proceeding based on a cost of service application typically lasts between seven (written hearing) and nine (oral hearing) months from the date of filing. As such, any new cost of service rates established for your utility may not be effective until well into the rate year. A standard incentive regulation mechanism application can be processed in substantially less time than a cost of service application.

Please be advised that, if the Board does not receive your cost of service application by **April 30, 2010**, any application that you file for 2010 rates should be filed on the basis of the 2nd generation incentive regulation mechanism.

Yours truly,

Original signed by

John Pickernell
Assistant Board Secretary

Ottawa River Power

283 pembroke street west – p.o. box 1087
pembroke, ontario K8A 6Y6
tel: (613) 732-3687 – fax: (613) 732-9838
web: www. orpowercorp.com

VIA E-MAIL

April 26, 2010

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge St.
Toronto, ON M4P 1E4

Attention: John Pickernell, Assistant Board Secretary

Dear Mr. Pickernell:

Thank you for your letter dated April 20, 2010 regarding the cost of service filing of Ottawa River Power Corporation (ORPC). It is understood that this type of application should be filed substantially before the beginning of the rate year. Given the limited resources of a utility of ORPC's size, as well as other factors, this did not happen.

In 2009 Ottawa River Power Corporation retained the services of Elenchus to assist with the filing of the cost of service application. To date ORPC has made considerable progress. In addition, Elenchus is now going to take the lead on the project. Given the amount of work already completed on this, the utility would incur significant incremental costs if obliged to defer the filing.

Therefore, ORPC respectfully asks the Board for an extension of this filing from the April 30th 2010 deadline as stated in your letter. Ottawa River Power Corporation is fully committed to file the cost of service application no later than June 30, 2010. The Board also has ORPC's assurance that for any reason the cost of service application cannot be completed by this date, an application for 2010 rates would be in the form of a straight forward IRM application.

Sincerely,

Douglas Fee
President & C.E.O

DRAFT ISSUES LIST

ORPC expects that the following matters pertaining to the 2010 Test Year may constitute issues in this Application:

- Capital spending and related depreciation
- Spending for Operations, Maintenance and Administration
- Load forecast
- Proposed retail delivery rates for transmission and low voltage services
- Proposed Total Loss Factors
- Proposed change to the Wholesale Market Service rate
- Cost of Capital
- Allowance for Payments in Lieu of Taxes
- Miscellaneous Revenues and offsets to Base Revenue Requirement
- Cost Allocation methodology
- Distribution rate design and proposed base distribution rates
- Disposition of deferral and variance account balances, and proposed rate riders
- Proposed funding adder for Smart Meters

UTILITY REPRESENTATIVES & WITNESSES

While ORPC requests that this Application be disposed of by way of a written hearing, the following preliminary list of potential witnesses is provided in the event that an oral hearing is convened. The *curricula vitae* for the witnesses will be provided in the event of an oral hearing.

- **Douglas Fee**, President, President, ORPC, responsible for the overall management of the corporation, including regulatory affairs.
- **Jane Wilkinson**, Chief Financial Officer, ORPC, responsible for all financial and regulatory functions of the corporation.
- **James Cochrane**, Senior Consultant, Elenchus Research Associates Inc., has extensive experience with a major utility in Ontario where he played key roles in corporate strategy, investment and operations planning, financial planning, performance measurement and analysis, conservation and demand management (CDM), and regulatory affairs. James is qualified to answer questions regarding the various models used for this application.
- **Stephen Motluk**, Senior Consultant, Elenchus Research Associates– Stephen prepared ORPC's load forecast is qualified to answer questions regarding selection of statistical methods and their application to the Load Forecast.

Exhibit 1: Administrative Documents

Tab 2 (of 4): Company Overview

DESCRIPTION SUMMARY

Ottawa River Power Corporation is an amalgamation of four former hydro utilities: Pembroke Hydro, Beachburg Hydro, Almonte Hydro and Killaloe Hydro. The history of the former utilities dates back to 1893 when the first electrical generation plant was established in Pembroke in conjunction with a lumber mill. This allowed for the installation of the first street lighting in Canada. Four years later, Pembroke Electric Light Company (PEL) was formed by a group of local businessmen who took over the generation. A new generation plant was built which used steam to drive an Edison DC generator and a Westinghouse AC generator. The distribution area was expanded throughout Pembroke and the surrounding area.

By 1904, more capacity was required and a generation plant was built on the Black River in Quebec with a 15 mile, 25 KV twin transmission line built into Pembroke. The old steam plant was closed since it was no longer needed with the new capacity from the Waltham Dam.

PEL continued to serve Pembroke as well as the surrounding area, both on the Ontario and Quebec side of the Ottawa River On orders of the Department of National Defense, the generation plant was expanded in 1940 to supply the rapid growth at CFB Petawawa to support the war effort. In 1931 a diesel generator (the largest stationary diesel in Canada at the time) was installed in Pembroke to provide additional peaking capacity and voltage support for the supply from Waltham.

PEL supplied the complete electrical requirements of the area until 1952 when, due to low water levels, a connection was made to the Ontario Hydro grid.

In 1967, the municipality of Pembroke bought the distribution assets within the City of Pembroke from PEL and Pembroke Hydro was formed. PEL later sold its remaining distribution assets within Ontario and Quebec to Ontario Hydro and Hydro Quebec.

Then in April 1999 Ottawa River Power Corporation was incorporated to comply with Bill 35 and the New Energy Act. On January 1, 2000 the former Pembroke Hydro and Beachburg Hydro amalgamated and started operating as this new corporation. On September 30, 2000 Killaloe Hydro and Almonte Hydro joined the amalgamation. The four municipalities are the shareholders of record and hold the following common shares:

- Corporation of the City of Pembroke - 4,364
- Corporation of the Township of Whitewater - 147
- Corporation of the Township of Killaloe, Haggarty & Richards – 169
- Corporation of the Town of Mississippi Mills – 888

At the same time, 1999, the four shareholders also formed Ottawa River Energy Solutions Inc., an affiliate of ORPC, and the retail assets of the former utilities were transferred to this company.

The letterhead of Ottawa River Power Corporation states that it is “a proud locally owned hydro utility”. It currently serves approximately 10,500 customers with offices located in both Pembroke and Almonte. ORPC prides itself in knowing its customers, personally handling phone calls and in the provision of excellent customer service.

ORPC has experienced the benefits of an amalgamated corporation and has been able to grow its retained earnings to $2.1 million. As of December 31, 2008 it had assets of $21 million including property, plant and equipment with a net book value of $8.4 million. It maintains gross revenues of more than $18 million per year.

ORPC does not produce an annual or interim formal report but uses the audited Financial Statements instead. ORPC does hold open annual shareholder’s meetings in the spring of each year where management and board members report on the activities of the corporation.

DISTRIBUTION SYSTEM

The urban communities served by ORPC are limited to the City of Pembroke, the Township of Whitewater (Beachburg only), the Town of Mississippi Mills (Almonte Ward only) and the Township of Killaloe, Haggarty & Richards (Killaloe only). Two exceptions to this geographic description are located in the Town of Mississippi Mills. During 2008 Ottawa River Power Corporation applied to the Ontario Energy Board to have its service area amended to include the west half of Lot 13 in the Township of Ramsey. This amendment was granted by the OEB under order EB-2008-0094. During 2009 ORPC applied to the OEB for another service area amendment in the Town of Mississippi Mills. In June 2009 the OEB amended the service area of ORPC under order EB-2009-0019 to include Phase 1 of Sadler Estates Development (Part of Lot 16, Conc. 10). The total service area is approximately 35.6 square kilometers.

ORPC has 146 kilometers of lines comprised of 127 kilometers of overhead lines and 19 kilometer of underground lines. The lines are made up of 94 kilometers of 3-phase wire, 1 kilometer of 2-phase wire, and 51 kilometers of single-phase wire. ORPC's distribution plant includes eleven substations: eight at 4.16 KV and three at 12.4 KV. Eight substations are located in the City of Pembroke and three substations are located in the Town of Mississippi Mills. Ottawa River Power Corporation has 14 sub-transmission transformers and 1592 distribution transformers.

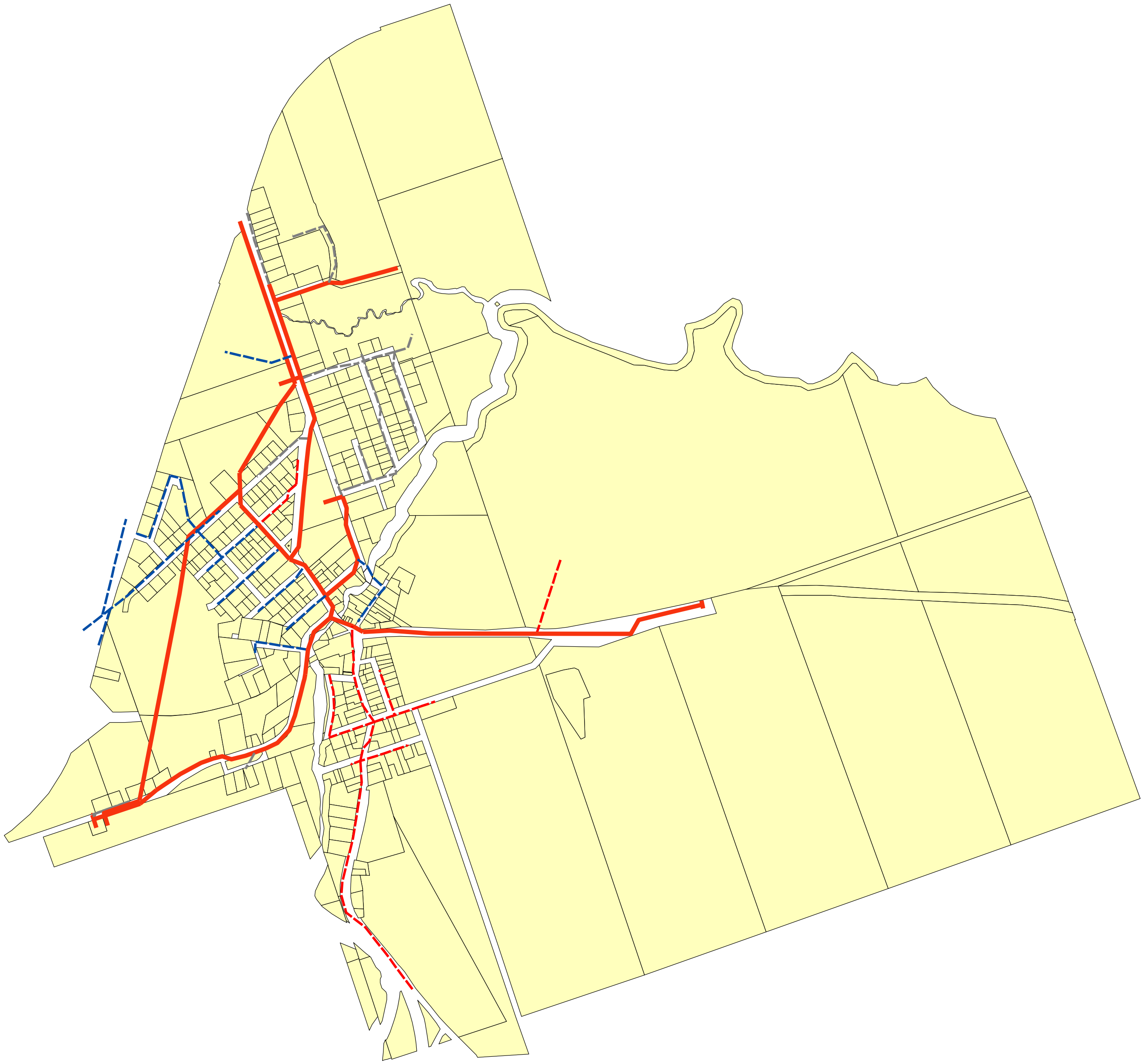
ORPC has a Scada system in the City of Pembroke that is staffed eight hours per day.

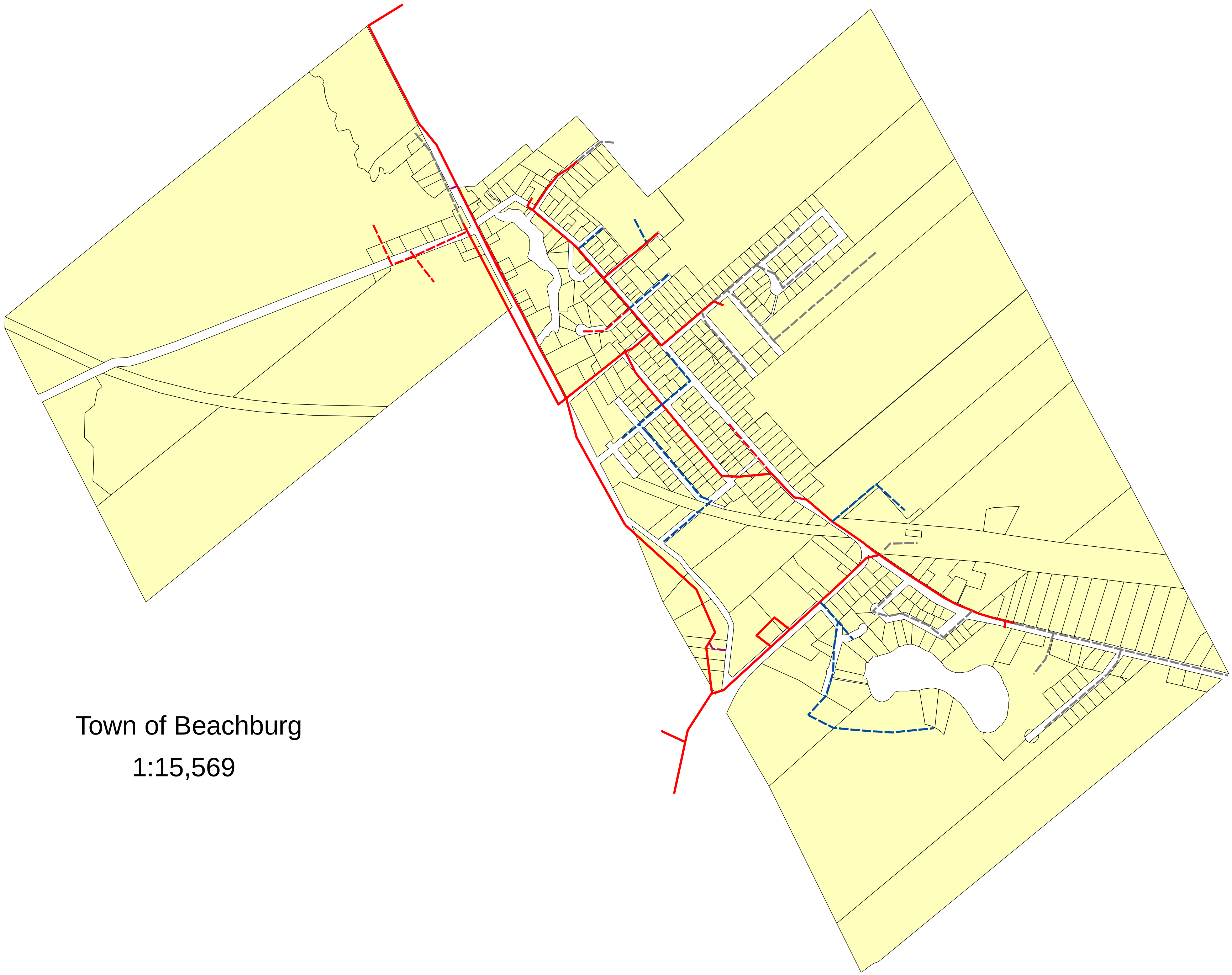
Attachment 1 (of 1):

Map of LDC's Distribution System

Town of Killaloe

1:20,000



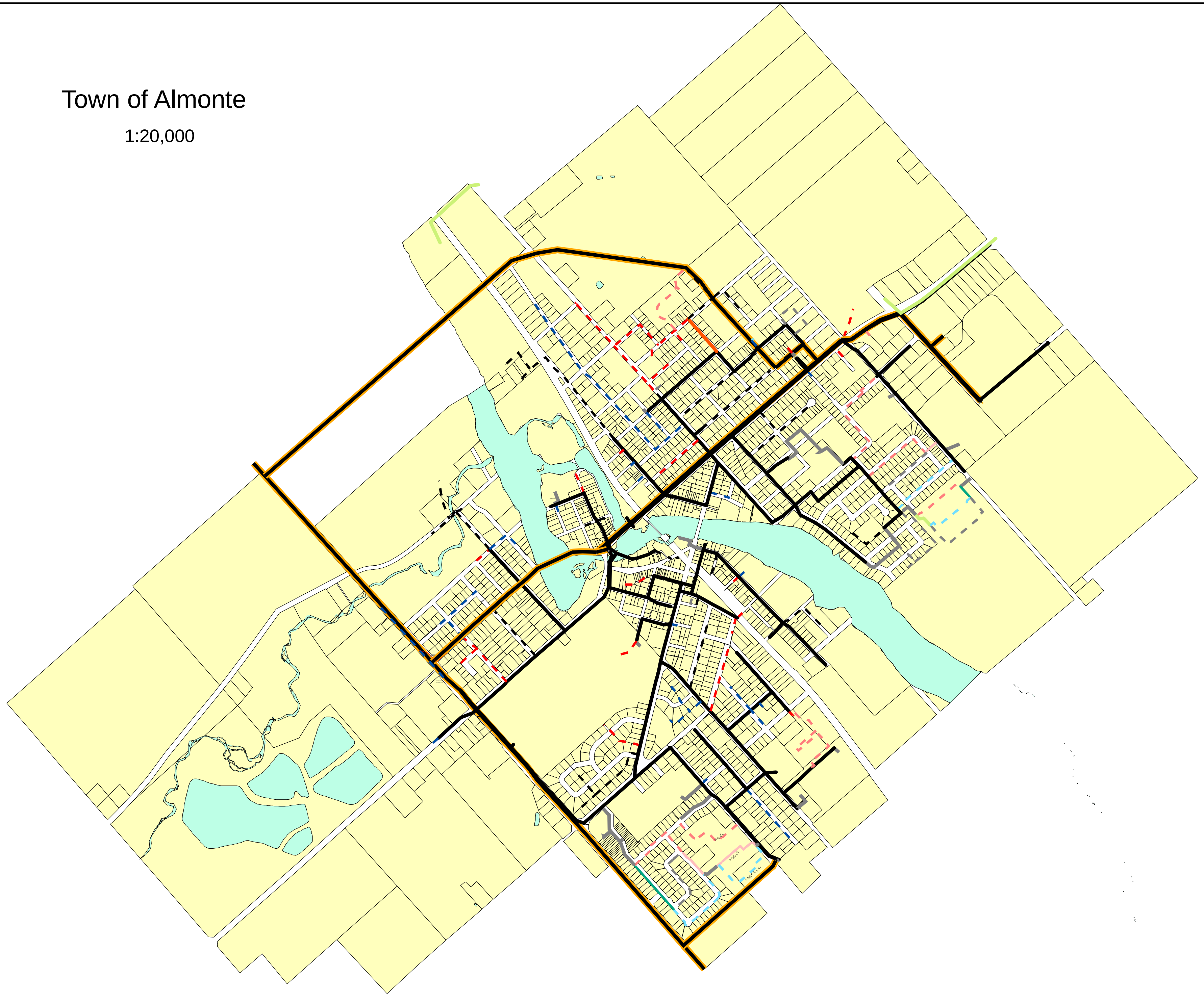


Town of Beachburg

1:15,569

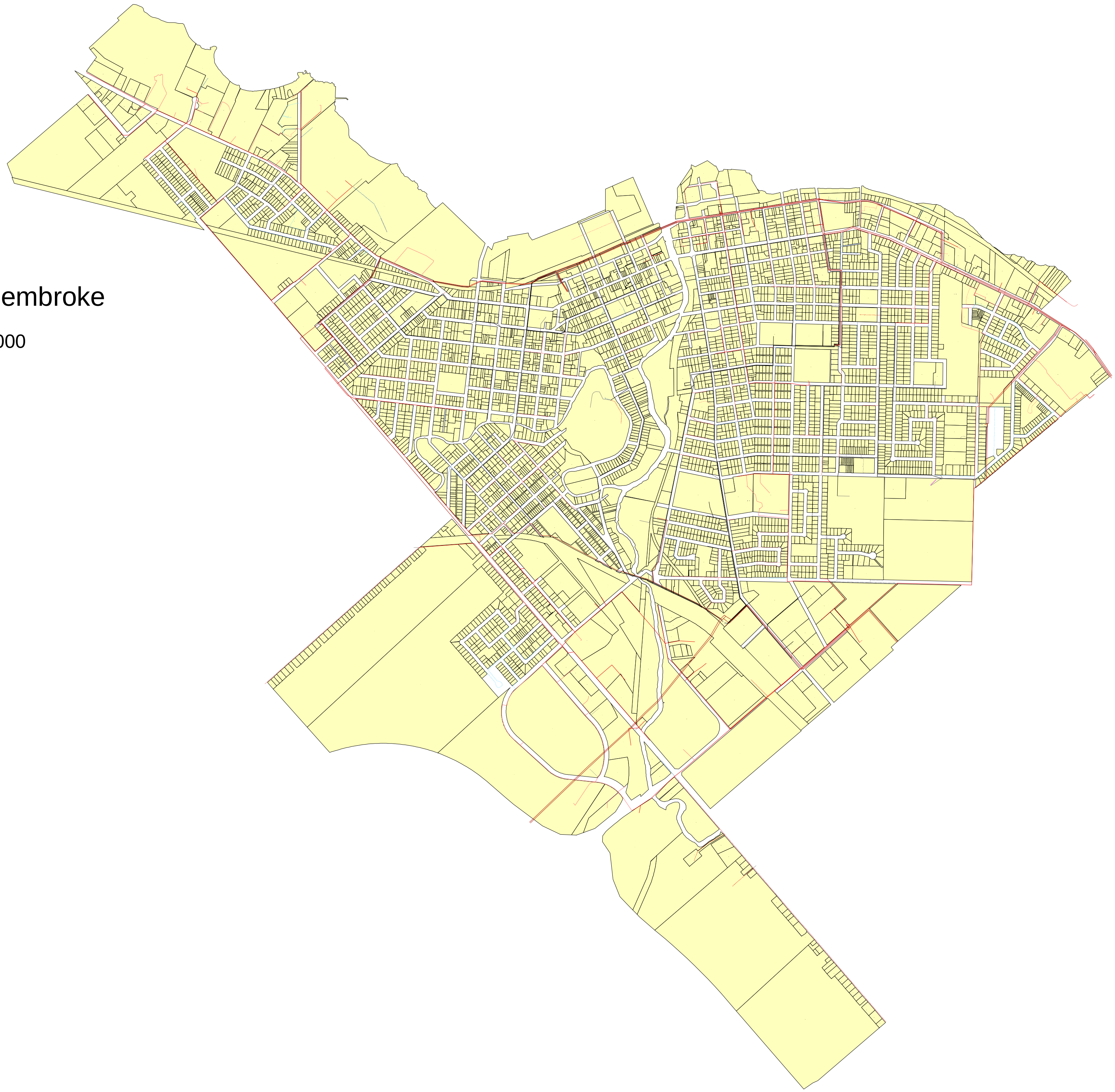
Town of Almonte

1:20,000



City of Pembroke

1:30,000



CORPORATE ORGANIZATION

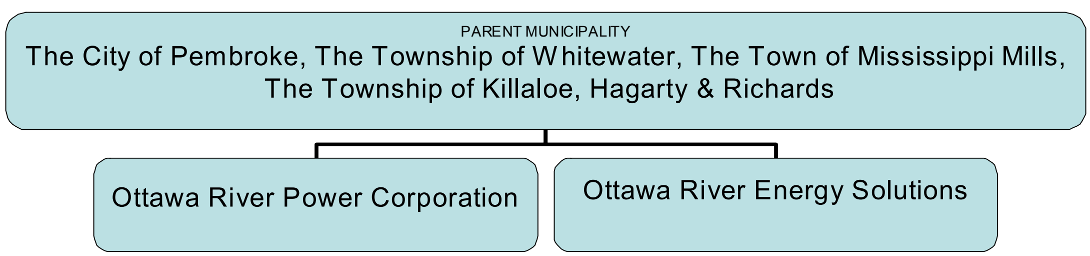
The parent municipalities, The City of Pembroke, the Township of Whitewater, the Town of Mississippi Mills and the Township of Killaloe, Hagarty & Richards are the sole shareholders of Ottawa River Power Corporation.

OPRC has an affiliate company namely Ottawa River Energy Solutions Inc. (ORES). The business activities of ORES include hot water tanks rentals, sentinel light rentals, meter reading services and a fibre optic network. Ottawa River Power Corporation provides construction contract services to ORES. ORES provided meter reading services until May 2009 to ORPC and continues to supply broadband services.

Each company maintains a separate board of directors consisting of seven members. These are comprised of four representatives from the City of Pembroke, and one representative from each of the remaining municipalities. Ottawa River Power Corporation meets the requirements for independence set out in Section 2.1.3 of the *Affiliate Relationships Code for Electricity Transmitters and Distributors*.

Attachment 1 (of 2):

Corporate Entities Relationships Chart



Attachment 2 (of 2):

Utility Organizational Chart

Ottawa River Power Corporation (ORPC)

Board of Directors
Ron Lowe - Chair
Doug Leach - Vice Chair
Garnet Kranz
Ed Jacyno
Shirley White
Marcel Mantha
Paul Finner

- Douglas Fee — President & CEO
  - Mary Hellingman — Administrative Assistant
  - Jane Wilkinson — CFO
    - Shelley Morris — Office Manager
      - Debbie O'Neill -Accounting
      - Pembroke
        - Bev Veaudry - Billing
        - Petra Pond - Billing/Data
        - Sheila Wendt - Collections
        - Lana Burns - Cashier
      - Almonte
        - Nicole Pederson - Billing
        - Teresa Rothwell - Billing(PT)
  - Lyle Jamieson — Superintendent-Lines
    - Pembroke
      - Bruce Tennant
      - Bob Miron
      - Reg Ballman
      - Charles Watson**
      - Jeff Boucher
      - Craig Shannick
    - Almonte
      - Dan Brady
      - Brian Stead
      - Jody Metcalfe
  - Brian Boudens** — Superintendent-Stations/Cust Service
    - Garry Gervais — Metering
    - Greg Kendall — Substation Maintenance
    - Paul Jones — Service
    - Roy Schroeder — Maintenance
  - Justin Allen — IT and Engineering Technician

** JHSC Co-chairs

AFFILIATE TRANSACTIONS

Ottawa River Power Corporation has an affiliation with Ottawa River Energy Solution Inc. (ORES). The business lines of ORES are comprised of the historical retail lines of the former amalgamated utilities. These include water heater, rentals, sentinel light rentals, contract work and telecommunications. ORES has no employees.

Ottawa River Energy Solutions Inc. has a seven member Board of Directors that is separate from Ottawa River Power Corporation. This is comprised of four members appointed by the City of Pembroke, and one member from the remaining three communities: Town of Mississippi Mills, Township of Whitewater and Township of Killaloe, Haggarty & Richards.

ORES provided meter reading services to Ottawa River Power Corporation on cost based pricing up until May 2009 when ORPC began in earnest the installation of smart meters. ORES continues to provide internet services to ORPC on market-based pricing. Ottawa River Power Corporation provides management and other services to ORES on a cost basis. A project and job costing system is used to track time, material and equipment for the services provided. Ottawa River Power Corporation has provided a loan to ORES for telecommunication development purposes. ORES pays interest on this loan monthly.

The affiliate service agreement is located at Exhibit 1, Tab 2, Schedule 4, Attachment 1. Details of the transaction are found at Exhibit 4, Tab 5, Schedule 1.

Attachment 1 (of 1):

Service Level Agreement(s)

THIS AGREEMENT made, in duplicate, this 01st day of May, 2002.

BETWEEN:

OTTAWA RIVER POWER CORPORATION

hereinafter called "Power"

OF THE FIRST PART

-and-

OTTAWA RIVER ENERGY SOLUTIONS INC.,

Hereinafter called "Energy"

OF THE SECOND PART

WHEREAS Energy and Power were incorporated on the 29th day of April, 1999.

AND WHEREAS Power was incorporated for the purposes of distribution of electricity in and for the Province of Ontario.

AND WHEREAS Energy was incorporated for the purposes of the retail of electricity and for the purposes of any and all activities related thereto and for the supply of electronics and electrical equipment and/or products and other programs and services.

AND WHEREAS the City of Pembroke, the Village of Beachburg, the Corporation of the Town of Mississippi Mills and the Corporation of the Town of Killaloe, Hagarty & Richards (formerly Killaloe Hydro-Electric Commission) amalgamated their various utilities in the County of Renfrew and the County of Lanark for the efficient and effective distribution of electricity and related products in the said counties.

AND WHEREAS the Province of Ontario, under Bill 35, has necessitated the separation of the competitive products in the electrical market from that of the essential wire services and as such Power and Energy were incorporated.

AND WHEREAS the Ontario Energy Board is the regulator of power corporations.

AND WHEREAS the Ontario Energy Board Affiliate Relationship Code outlines the degree of separation, the sharing of services and resources, the transfer of pricing, consideration concerning financial transactions with affiliates and other matters.

AND WHEREAS Energy and Power have agreed to perform those services as necessary at their own expense.

AND WHEREAS the parties hereto wish to enter into an agreement to provide for the delivery of services between the affiliates, as per the service requirements provided for in the *Ontario Energy Board – Affiliate Relationships Code for Electricity Distributors and Transmitters* and for other matters as set out in this agreement.

AND WHEREAS the objectives of this agreement are to establish the rules for the inter-operation of Power and Energy and to ensure that they will be in compliance with the *Ontario Energy Board Affiliate Relationship Code for Electricity Distributors and Transmitters* and to establish an outline of how the various functions to be undertaken by each corporation shall be administered between the two corporations for the servicing and financing arrangements between the two parties.

NOW THEREFORE in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1. Definitions

   a) Act means the Ontario Energy Board Act. 1998;

   b) Board means the Ontario Energy Board

   c) Confidential Information means information either of the parties have obtained relating to a specific consumer, retailer or generator in the process of providing current or respective utility service.

   d) Fair Market Value means the price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act.

   e) Information of Services means computer systems, services, data bases and persons knowledgeable about the utilities information technology systems.

2. General

   a) Power and Energy will operate entirely separate from the other, with a division and separation of resources, expenditures and administration.

   b) Power and Energy will maintain separate accounting records and maintain separate bank accounts.

   c) Power and Energy acknowledge that, although they are utilizing the same physical office location, they will ensure a physical separation from each other in the building.

   d) Power and Energy agree that they will maintain a division of directors so that at least one-third of the board of directors of power is independent from Energy.

3. Accounting

a) Power will perform all accounting procedures and work related thereto for Energy on an as-needed basis pursuant to direction and work orders from Energy. The accounting work performed by Power for Energy shall include, but not be limited to, the setting up of all books of general ledger for Energy.

b) Power shall not complete the auditing of any books for Energy and each Power and Energy, shall maintain and select an accounting firm for auditing of their respective books.

4. Administration

a) Power shall perform work for Energy including whatever administration work Energy requires as well as billing and collecting of accounts.

b) Energy shall provide to Power its request for work and services to be performed by Power for administration by way of work orders.

5. Incremental and Ancillary Expenses

a) Energy may use, telephone and computers of Power and shall be invoiced for usage based on a time basis.

b) In the event that Energy requires any other equipment not referred to in (a) herein, it may be utilized by Energy upon prior scheduling notice and pursuant to the requisite work orders.

6. Confidentiality of All Matters

a) It is agreed by the parties that each shall maintain confidentiality with respect to its business operations being conducted.

b) Power and Energy have in place, and will maintain for that purpose, appropriate computer data management and data access protocols, as well as provisions regarding the breach of any access protocols.

c) Power and Energy, while sharing employees, shall ensure that such employees are not directly involved in collecting or have access to confidential information of the other and shall prepare the necessary data access protocols and data management to ensure confidentiality between Power and Energy.

d) Power shall not disclose confidential information to Energy, without the consent in writing of the consumer, retailer or generator, as the case may be, except where the confidential information is required to be disclosed:

    i. For billing or market operation purposes;
    ii. For law enforcement purposes;
    iii. For the purposes of complying with a legal requirement;
    iv. For the processing of past due accounts of the consumer, which have been passed to a debt collection agency.

e) Irrespective of the provisions of Paragraph (d) above, confidential information may be disclosed by Power where the information has been sufficiently aggregated, such that any individual consumer, retailer, or generator's information could not reasonably be identified. If such information is aggregated, it must be disclosed on a non-discriminatory basis to any party requesting the information.

7. <u>Sharing of Employees</u>

a) The parties hereto agree that, from time to time, Power and Energy may share employees but will ensure compliance with the confidentiality provisions as referred to in Paragraph 6(a) above.

b) Power and Energy hereby agree that they will not share employees that carry out the day to day operation of the Power's transmission or distribution network.

8. Services to be Performed by Power and Energy for Each Other

a) The parties hereto agree that where each provides a service, resource or product to the other, they shall ensure that the sale price is no less than the fair market value of the service, resource or product.

b) The parties hereto agree that in purchasing a service, resource or product from each other, they shall pay no more than fair market value for it. In the event that fair market value cannot be determined by tendering, the parties shall charge to each other no less than a "cost based price" and pay to each no more than a cost based price. The cost based price shall reflect the cost of producing the service or produce, including a return on invested capital. The return component shall be the higher of the utilities' approved rate of return or the bank prime rate.

c) The parties hereto agree that each shall not sell any assets to the other for a price less than the net book value of the said assets.

9. Limited Liability

The parties hereto agree that neither shall be responsible to the other or to anyone claiming through the other, or to any third party, for any loss, cost (including lawyer's and court costs), damage, injury, liability, claim, penalty, fine interest, act of God, or any course of action whatsoever resulting howsoever from the other unless it is proven that the other is negligent.

10. Insurance

The parties hereto acknowledge that they have policies of insurance, with the named insureds being ORES, ORPC and also a Certificate of Insurance through the Municipal Electric Association reciprocal Insurance Exchange with the named insureds being ORES and ORPC. The parties shall maintain in force these policies of insurance to provide for their respective liabilities. Each party shall assume their respective obligation for payment of the said premiums pursuant to the policies as agreed to by the parties.

11. Invoicing

Power and Energy shall invoice each other respectively, monthly, following the performance of the service or sale of the resource or product. All invoiced amounts and accounts shall be due and payable upon receipt with overdue accounts subject to interest at the rate of 18% per annum.

12. Financial Transmissions, Security and Interest

a) ORPC shall provide loan advances to ORES up to a maximum of $600,000 to assist ORES in their operations.

b) The outstanding indebtedness, provided by ORPC to ORES shall be secured by a Promissory Note and other security to be provided by ORES to ORPC in a form as required by ORPC, including but not limited to a General Security Agreement, Assignment of Assets and/or registration under the Personal Property Security Registrations Act.

c) ORES shall pay interest to ORPC on the amount of the advances of ORPC to ORES as referred to in Paragraph (b) herein, at the prime rate of the Royal Bank of Canada, calculated semi-annually and payable once each year, on the 30th day of April of each and every year, with such interest calculation to commence on the date of market opening, being May 01st, 2002, and the first payment of interest to be made on April 30th, 2003.

d) ORES shall pay its entire indebtedness owed to ORPC upon demand by ORES, together with interest.

13. Miscellaneous

a) ORPC shall take all reasonable steps to ensure that Energy does not use Power's name, logo or other distinguishing characteristics in the manner which would mislead consumers as to the distinction between Power and Energy.

b) Power, including its employees and agents, shall not state or imply to consumers a preference for Energy.

14. Service Agreement and Affiliate Code Requirements

a) The parties hereto agree and acknowledge that this agreement constitutes a service agreement as provided for by the *Ontario Energy Board ("OEB")* and the *Affiliate Relationships Code for Electricity Distributors and Transmitters.*

b) In the event that the *Ontario Energy Board* requires amendments to the Service Agreement, the parties shall comply with any legislation or code requirements and the parties shall work with the OEB in completing such amendments, as required.

15. Arbitration

All matters in difference between the parties in relation to this agreement shall be referred to the arbitration of a single arbitrator, if the parties agree upon one, otherwise to three arbitrators, one to be appointed by each party and a third to be chosen by the first two named before they enter upon the business of arbitration. The award and determination of the arbitrator or arbitrators or any two of the three arbitrators shall be binding upon the parties and their respective heirs, executors, administrators and assigns.

16. Benefit and Binding Nature of this Agreement

This agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

17. Effective Date

This agreement shall take effect on the 01st day of May, 2002.

IN WITNESS WHEREOF the parties hereto have hereunto set their hands and seals on the date first above written.

SIGNED, SEALED AND DELIVERED in the presence of	**OTTAWA RIVER POWER CORPORATION,**
	Per: ______________
	Per: ______________
	OTTAWA RIVER ENERGY SOLUTIONS INC.,
	Per: ______________
	Per: ______________

Exhibit 1: Administrative Documents

Tab 3 (of 4): Board Directions

BOARD DIRECTIONS FROM PREVIOUS EDR DECISIONS

ORPC has no outstanding directions from previous EDR Decisions.

ACCOUNTING ORDERS

ORPC has not had any accounting orders issued from the Ontario Energy Board.

COMPLIANCE ORDERS

ORPC has not received any compliance orders from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR, and no such orders are outstanding presently.

In 2007, ORPC sought clarification from the OEB regarding the renewal of a supply contract with Brookfield Energy Management Inc. (BEMI), On February 22, 2008 the OEB's Chief Compliance Officer issued Compliance Direction CO-2007-0060. The direction indicated that ORPC needed to seek an exemption to the Retail Settlement and the Standard Service Supply Codes, or discontinue purchasing electricity supply from BEMI by March 31, 2008.

OPRC, and its predecessor utility, Pembroke Hydro, have been purchasing power from this Waltham generator since 1904. In 2002, after a meeting between representatives of the Ontario Energy Board, Brookfield Energy Management Inc. and Ottawa River Power Corporation, ORPC entered into a contract to purchase electricity from BEMI's Waltham generating station, which is located outside of ORPC's licensed service area. The contract price was set at the Hourly Ontario Energy Price plus $2.48/kW, which represented 50% of the savings to ORPC for transmission and network charges.

When the contract came up for renewal ORPC contacted the OEB to request clarification about the continuation of the sharing of market charge savings with the generator. This caused the compliance direction to be issued.

In response to the direction, ORPC sent a letter to the compliance office asking for an extension of the March 31, 2008 deadline. This was granted and on August 20, 2008 Ottawa River Power Corporation filed an exemption request to allow for the purchase of electricity from BEMI. This was assigned Board File #EB-2008-0289.

On March 27, 2009 the Ontario Energy Board provided an Interim Decision allowing the exemption from the Retail Settlement Code and the Standard Service Supply code until August 1, 2009. This allows ORPC to continue to purchase electricity from BEMI under the old contract. ORPC was ordered to file a copy of the new contract negotiated with Brookfield Energy along with a short submission outlining the benefits of this contract by June 1, 2009. This was filed on May 27, 2009.

ORPC received a decision and order dated July 22, 2009. “Ottawa River is granted, for the duration of the contractual agreement between Ottawa River and Brookfield Energy, an exemption from section 2.2.2 of the Standard Supply Code and section 3.2 of the Retail Settlement Code. Accordingly, Schedule 3 of Ottawa River Power Corporation’s Electricity Distribution Licence ED-2003-0033 is amended (attached) in accordance with this Decision.”

OTHER BOARD DIRECTIONS

ORPC has not received any other utility-specific directions from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR, and no such directions are outstanding presently.

Exhibit 1: Administrative Documents

Tab 4 (of 4): Finance

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of the Ottawa River Power Corporation are the representation of management prepared in accordance with Canadian generally accepted accounting principles and accounting guidance provided by its regulator, the Ontario Energy Board ("OEB"), as contained in its Accounting Procedures Handbook, under the authority of the Ontario Energy Board Act, 1998.

The following is a summary of significant accounting policies of the corporation:

Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

Revenue recognition:

Revenue from the sale of electricity is recognized on the accrual basis, which includes an estimate of unbilled revenue which represents electricity consumed by customers since the date of each customer's last meter reading. Actual results could differ from estimates made of electricity usage. The related cost of power is recorded on the basis of power used.

Labour on customer premises is generally short-term in nature. Revenue is recognized in the period the work is completed.

Interest is recognized on the accrual basis.

Measurement uncertainty:

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered and include an appropriate allowance for unrecoverable amounts. Inventories are recorded net of provisions for obsolescence.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

Inventory:

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031 - "Inventories" which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment.

The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have any impact on the Corporation's results of operations.

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on the lower of a weighted-moving average basis or replacement cost. The Corporation has retrospectively reclassified all major future components of its electricity distribution system infrastructure from inventory to property, plant and equipment. Once capitalized, these items are not amortized until they are put into service.

Property, plant and equipment:

Capital assets are recorded at cost and include contracted services, materials, labour, engineering costs, and overheads. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be 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 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.

Amortization of capital asset values is charged to operations on a straight-line basis over their estimated service lives.

Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits and invested in term deposits, which are reported separately from the Corporation's own cash and cash equivalents. Interest is paid on customer balances at rates established from time to time by the Corporation.

Pension and other post-employment benefits:

The Corporation accounts for its participation in the Ontario Municipal Employees Retirement Funds ("OMERS"), a multi-employer public sector pension funds, as a defined contribution plan.

The Corporation 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.

Regulatory assets and liabilities:

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in rates. Regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding regulated retail transmission, wholesale market, and cost of power rates charged to the utility. Post market-opening retail settlement variances are variances that occur between the amount charged by Hydro One to Ottawa River Power Corporation and the amounts collected from customers. These include the cost of power, as well as the wholesale market settlement charge and retail transmission charges.

Corporate income and capital taxes:

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in The Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations.

The Corporation provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes.

HISTORICAL FINANCIAL STATEMENTS

The following audited financial statements are attached:

Table 1: Audited Financial Statements

Attachment 1	Year ended 31 December, 2007
Attachment 2	Year ended 31 December, 2008
Attachment 3	Year ended 31 December, 2009

Attachment 1 (of 3):

2007 Audited Statements with 2006 comparative information

Financial Statements of

OTTAWA RIVER POWER CORPORATION

Year ended December 31, 2007

SCOTT ROSIEN & DEMPSEY

Chartered Accountants

D.M. Scott, C.A.
D.W. Rosien, C.A.
W.T. Dempsey, C.A.

545 Pembroke Street West
Pembroke, Ontario K8A 5P2

TELEPHONE: 613-735-3981
FAX: 613-732-3829

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheet of Ottawa River Power Corporation as at December 31, 2007 and the statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company 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.

Chartered Accountants
Licensed Public Accountants

Pembroke, Ontario
March 12, 2008

OTTAWA RIVER POWER CORPORATION

(Incorporated under the laws of Ontario)
Balance Sheet

December 31, 2007, with comparative figures for 2006

	2007	2006
Assets		
Current assets:		
Cash and cash equivalents	$ 5,203,793	$ 3,856,650
Accounts receivable (note 2)	1,286,958	1,013,917
Amounts in lieu of income taxes recoverable	75,124	-
Due from Ottawa River Energy Solutions Inc. (note 3)	292,487	431,376
Unbilled revenue	2,587,439	2,444,204
Inventory (note 4)	892,357	804,895
Prepaid expenses	129,532	138,780
	10,467,690	8,689,822
Restricted cash and cash equivalents:		
Cash and cash equivalents, held for customer deposits	115,344	328,651
Cash and cash equivalents, held for regulatory liability	2,381,507	2,499,002
	2,496,851	2,827,653
Property, plant and equipment (note 5):		
Land, building, distribution and office equipment and motor vehicles	22,361,953	21,585,301
Accumulated amortization	14,196,879	13,447,569
	8,165,074	8,137,732
	$ 21,129,615	$ 19,655,207

	2007	2006

Liabilities and Shareholders' Equity

	2007	2006
Current liabilities:		
Accounts payable and accrued liabilities	$ 5,002,229	$ 3,054,345
Payable in lieu of income taxes	-	36,151
Current portion of long-term debt	115,344	223,253
	5,117,573	3,313,749
Regulatory liability (note 6)	2,381,507	2,499,002
Long-term debt (note 7)	5,746,182	5,876,401
Shareholders' equity:		
Capital stock		
Authorized:		
Unlimited number of non-cumulative special shares		
Unlimited number of common shares		
Issued (note 8):		
5,568 Common shares	5,585,838	5,585,838
Retained earnings	2,298,515	2,380,217
	7,884,353	7,966,055
Lease commitments (note 11)		
Contingencies (note 12)		
	$ 21,129,615	$ 19,655,207

See accompanying notes to financial statements.

On behalf of the Board:

____________________ Director

____________________ Director

OTTAWA RIVER POWER CORPORATION

Statement of Earnings

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Service revenue:		
Residential	$ 7,649,827	$ 8,065,700
General	10,513,896	10,236,033
Street lighting	250,801	266,648
	18,414,524	18,568,381
Cost of power	14,954,963	14,896,345
	3,459,561	3,672,036
Other operating revenue (note 15)	483,068	439,355
	3,942,629	4,111,391
Operating and maintenance expenses:		
Distribution	809,070	754,580
Utilization	57,886	71,038
Billing and collecting	530,896	507,147
General and administrative	938,580	724,841
Capital tax	22,850	31,000
Amortization	693,825	697,057
Interest on long-term debt	404,973	404,973
Interest on regulatory liability	101,121	108,637
	3,559,201	3,299,273
Earnings before amounts in lieu of income taxes	383,428	812,118
Amount in lieu of income taxes (note 9)	75,370	229,775
Net earnings	$ 308,058	$ 582,343

See accompanying notes to financial statements.

OTTAWA RIVER POWER CORPORATION
Statement of Retained Earnings

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Retained earnings, beginning of year	$ 2,380,217	$ 2,076,274
Net earnings	308,058	582,343
Dividends paid	(389,760)	(278,400)
Retained earnings, end of year	$ 2,298,515	$ 2,380,217

See accompanying notes to financial statements.

OTTAWA RIVER POWER CORPORATION

Statement of Cash Flows

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Cash provided by (used in):		
Operations:		
Cash received from customers	$ 18,338,652	$ 18,614,457
Cash paid to suppliers and employees	(15,358,161)	(17,929,914)
Interest earned	281,553	243,577
Interest paid	(506,094)	(513,610)
Corporate income and capital taxes paid	(209,495)	(366,879)
	2,546,455	47,631
Financing:		
Dividends paid	(389,760)	(278,400)
Investments:		
Customer deposits, sick leave and post retirement benefits	(24,821)	(24,828)
Additions to property, plant and equipment	(784,731)	(535,813)
	(809,552)	(560,641)
Increase (decrease) in cash	1,347,143	(791,410)
Cash and cash equivalents, beginning of year	3,856,650	4,648,060
Cash and cash equivalents, end of year	$ 5,203,793	$ 3,856,650

See accompanying notes to financial statements.

Ottawa River Power Corporation (the "Corporation") was incorporated under the Business Corporations Act (Ontario) on April 22, 1999. Ottawa River Power Corporation is the successor to the former Pembroke Hydro Electric Commission ("Pembroke Hydro"), the Beachburg Hydro System ("Beachburg Hydro"), the Township of Killaloe, Haggarty & Richards Hydro Electric Commission ("Killaloe Hydro") and the Town of Mississippi Mills Public Utilities Commission ("Almonte Hydro"). The Corporation is the electric distribution utility for residents of the City of Pembroke, the Village of Beachburg, the Township of Killaloe and the Town of Mississippi Mills (Almonte Ward).

1. Significant accounting policies:

(a) Basis of presentation:

The financial statements of the Ottawa River Power Corporation are the representation of management prepared in accordance with Canadian generally accepted accounting principles and accounting guidance provided by its regulator, the Ontario Energy Board ("OEB"), as contained in its Accounting Procedures Handbook, under the authority of the Ontario Energy Board Act, 1998.

(b) Rate setting:

Ottawa River Power 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.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in the change in the timing of accounting recognition from that which would have applied in an unregulated company. Specifically, the following accounting treatments have been applied:

(i) Capital and operating costs incurred in respect of the transition to competitive markets have been deferred with amortization to commence at a date that a rate increase is implemented to offset the amortization of the transition costs. In November 2003, the Province of Ontario introduced the Ontario Energy Board Amendment Act (Electricity Pricing) 2003 (the "2003 Act"). The 2003 Act will impact both the distribution and energy rates charged to customers and includes a provision for the recovery of regulatory assets (note 1(j)).

(ii) An amount to represent the cost of funds used during construction and development has been applied based on the value of construction in progress.

(iii) The Corporation provides for amounts in lieu of corporate income taxes using the taxes payable method for its regulated business activities.

1. Significant accounting policies (continued):

(iv) The Corporation has deferred certain pre-market opening cost of power variances and post-market opening retail settlement variances in accordance with Article 490 of the OEB's Accounting Procedures Handbook.

(c) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

(d) Revenue recognition:

Revenue from the sale of electricity is recognized on the accrual basis, which includes an estimate of unbilled revenue which represents electricity consumed by customers since the date of each customer's last meter reading. Actual results could differ from estimates made of electricity usage. The related cost of power is recorded on the basis of power used.

Labour on customer premises is generally short-term in nature. Revenue is recognized in the period the work is completed.

Interest is recognized on the accrual basis.

(e) Measurement uncertainty:

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered and include an appropriate allowance for unrecoverable amounts. Inventories are recorded net of provisions for obsolescence.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

(f) Inventory:

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on the lower of a weighted-moving average basis or replacement cost.

(g) Property, plant and equipment:

Capital assets are recorded at cost and include contracted services, materials, labour,

1. Significant accounting policies (continued):

engineering costs, overheads and an allowance for the cost of funds used during construction when applied. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be 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 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.

Amortization of capital asset values is charged to operations on a straight-line basis over their estimated service lives as follows:

	Estimated service life	
	Range	Average
Land rights	25 to 30 years	30
Buildings	30 to 60 years	50
Poles, towers and fixtures	25 to 40 years	25
Overhead conductors and devices	25 to 40 years	25
Underground conduit	25 to 40 years	25
Underground conductors and devices	25 to 40 years	25
Services	3 to 10 years	5

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

An allowance for the cost of funds used during the construction period may be applied. The rate applied is equal to the rate allowed by the OEB in respect of long-term borrowings, being 6.9%.

(h) Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits and invested in term deposits, which are reported separately from the Corporation's own cash and cash equivalents. Interest is paid on customer balances

1. Significant accounting policies (continued):

at rates established from time to time by the Corporation.

(i) Pension and other post-employment benefits:

The Corporation accounts for its participation in the Ontario Municipal Employees Retirement Funds ("OMERS"), a multi-employer public sector pension funds, as a defined contribution plan.

The Corporation 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.

(j) Regulatory assets and liabilities:

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in rates. Regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding regulated retail transmission, wholesale market, and cost of power rates charged to the utility. The OEB directs the distribution utilities to defer these variances for future true-up with the Independent Electricity Systems Operator ("IESO").

Post market-opening retail settlement variances are variances that occur between the amount charged by Hydro One to Ottawa River Power Corporation and the amounts collected from customers. These include the cost of power, as well as the wholesale market settlement charge and retail transmission charges. The variances incurred up to December 31, 2004 have been recovered in rates up to April 30, 2008. The variances incurred from January 1, 2005 onward will be disposed of in a future proceeding.

In 2005 a new price plan for residential, low-volume and designated electricity consumers was introduced. At the request of the Minister of Energy, the Ontario Energy Board developed an electricity price plan that provides stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators. Effective Nov 1, 2007, eligible consumers pay 5.0 cents per kilowatt hour (kWh) up to a certain threshold each month and 5.9 cents per kWh for electricity used per month over this amount. This amount is reflected on the "Electricity" line on consumers' bills.

The price threshold - the amount of electricity that is charged at the lower price - changes twice a year for residential consumers. The price threshold will be 600 kWh per month in the summer (May 1st to October 31st) and 1,000 kWh per month in the winter (November 1st to

1. Significant accounting policies (continued):

April 30th). Prices are reviewed and may change every six months based on an updated Ontario Energy Board forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous period.

Management continues to believe that it is probable the regulatory assets will be fully recovered. In the event that recovery from future rates is no longer considered probable or portions of those amounts deferred are determined not to be recoverable, such amounts will be expensed in the period this determination is made.

(k) Corporate income and capital taxes:

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in The Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations.

The Corporation provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes.

(l) Financial instruments:

In 2005, The Canadian Institute of Chartered Accountants ("CICA") issued Handbook Section 3855, Financial Instruments - Recognition and Measurement, Handbook Section 1530, Comprehensive Income, Handbook Section 3251, Equity, and Handbook Section 3865, Hedges. The new standards are effective for the Corporation's annual financial statements commencing January 1, 2007.

Under these standards, all of the Corporation's financial assets are classified as loans and receivables. Loans and receivables and all financial liabilities are carried at amortized cost using the effective interest rate method. Upon adoption, the Corporation determined that none of its financial assets are classified as held-to-maturity, available-for-sale or held-for-trading and none of its financial liabilities are classified as held-for-trading. The classification provisions of the new standards had no impact on the financial statements.

1. Significant accounting policies (continued):

In 2006, the CICA issued Handbook Section 3862, Financial Instruments - Disclosures, and Handbook Section 3863, Financial Instruments - Presentation. These new standards will become effective for the Corporation beginning January 1, 2008. The Corporation is currently assessing the impact of these two new standards.

It is management's opinion that the facility is not exposed to significant interest, currency or credit risks arising from its financial instruments.

2. Accounts receivable:

	2007	2006
Residential and commercial energy and rentals	$ 1,115,459	$ 901,256
Work at customers premises	112,634	114,043
Municipal street lights	4,636	7,534
Employee purchases	3,739	7,143
Due from Brascan Energy Marketing Inc.	25,565	1,620
GST receivable	94,925	52,321
	1,356,958	1,083,917
Allowance for doubtful accounts	(70,000)	(70,000)
	$ 1,286,958	$ 1,013,917

3. Related party transactions:

(a) The Corporation provides electricity and services to the principal shareholder, the City of Pembroke. Electrical energy is sold to the City at the same prices and terms as other electricity customers consuming equivalent amounts of electricity. Street lighting maintenance services are provided at rates determined in relation to other service providers. Other construction services are provided at cost. A summary of amounts charged by the Corporation to the City of Pembroke are as follows:

	2007	2006
Electrical energy	$ 632,867	$ 609,568
Street lighting energy	205,000	210,916
Street light maintenance	32,863	30,560
Traffic light maintenance	4,076	4,076
	$ 874,806	$ 855,120

3. Related party transactions (continued):

At December 31, 2007, there are no accounts payable and accrued liabilities due to the City of Pembroke and accounts receivable include $112,554, (2006 - $125,991) from the City of Pembroke.

(b) The Corporation provides services to an affiliated company, Ottawa River Energy Solutions Inc., at cost. A summary of amounts charged by the Corporation to the Ottawa River Energy Solutions Inc. are as follows:

	2007	2006
Labour on customer premises	$ 22,359	$ 23,570
Interest - Ottawa River Energy Solutions Inc.	24,447	28,741
	$ 46,806	$ 52,311

At December 31, 2007, there are no accounts payable and accrued liabilities due to Ottawa River Energy Solutions Inc. Commencing January 1, 2003, interest is charged at the Royal Bank of Canada prime rate, calculated semi-annually and payable on April 30. The amount is secured by a general security agreement and is due on demand. Ottawa River Energy Solutions Inc. is affiliated by virtue of common ownership.

4. Inventory:

	2007	2006
Line material	$ 540,093	$ 486,935
Meters	113,327	108,638
Transformers	238,937	209,322
	$ 892,357	$ 804,895

5. Property, plant and equipment:

	Cost	Accumulated amortization	2007 Net book value	2006 Net book value
Land and land rights	$ 141,308	$ 6,051	$ 135,257	$ 135,592
Buildings	421,116	233,026	188,090	174,769
Poles, towers and fixtures	7,834,385	4,914,849	2,919,536	2,808,861
Overhead conductors and devices	4,589,871	2,434,575	2,155,296	2,224,097
Underground conduit	2,698,774	1,727,049	971,725	1,053,100
Underground conductors and devices	2,769,778	1,648,168	1,121,610	1,029,608
Services	3,906,721	3,233,161	673,560	711,705
	$ 22,361,953	$ 14,196,879	$ 8,165,074	$ 8,137,732

During the year, no provision for the cost of funds used during construction was capitalized.

During the period, total amortization recorded as operating and maintenance expenses amounted to $757,389, (2006 - $766,378).

6. Regulatory liability:

It is expected that the Corporation will apply for, and receive, in its electricity rates an allowance to remit the remaining regulated liabilities and an allowance to recover the remaining regulatory assets (note 1(j)).

	2007	2006
Assets (liabilities):		
Pre market opening energy variance	$ -	$ 53,443
Post market opening energy variance	(426,653)	(1,118,035)
Post market opening wholesale market service rate variance	(1,042,213)	(624,725)
Post market opening network transmission service variance	(201,093)	(606,745)
Post market opening network connection service variance	(742,718)	(334,320)
Hydro One post market opening variance	(177,682)	(404,506)
Deferred transition costs	-	339,181
Post market opening Provincial benefit variance	168,885	286,531
Other post market opening variances	160,058	102,169
Other regulatory assets	153,196	173,928
Regulated liabilities repaid	(148,668)	(154,165)
Post market opening variance interest	(188,615)	(195,607)
Other regulatory liabilities	63,996	(16,151)
	$ (2,381,507)	$ (2,499,002)

7. Long-term debt:

	2007	2006
7.25% Promissory note payable to the Corporation of the City of Pembroke, due May 1, 2022	$ 4,364,000	$ 4,364,000
7.25% Promissory note payable to the Corporation of the Village of Beachburg, due May 1, 2022	147,000	147,000
7.25% Promissory note payable to the Corporation of the Township of Killaloe, Haggarty and Richards, due May 1, 2022	172,348	172,348
7.25% Promissory note payable to the Corporation of the Town of Mississippi Mills, due May 1, 2022	902,490	902,490
Customer deposits	230,688	250,319
Vested sick leave	-	203,497
Post-retirement benefits	45,000	60,000
	5,861,526	6,099,654
Current portion of long-term debt	115,344	223,253
	$ 5,746,182	$ 5,876,401

The notes bear interest at 7.25%, with the term and interest rate to be re-negotiated annually. Interest is calculated annually, payable quarterly to the shareholders. The aggregate maturities of long-term debt for each of the two years subsequent to December 31, 2007 are as follows: 2008 - $115,344; and 2009 - $115,344.

8. Capital stock:

As at December 31, 2007, the common shares of the corporation are held as follows:

	Common Shares	Percentage Ownership
Corporation of the City of Pembroke	4,364	78.38%
Corporation of the Village of Beachburg	147	2.64%
Corporation of the Township of Killaloe, Haggarty and Richards	169	3.04%
Corporation of the Town of Mississippi Mills	888	15.94%
	5,568	100.00%

The common share ownership has not changed from prior year.

9. Payment in lieu of corporate income taxes:

The Corporation follows the taxes payable method of accounting for amounts paid in lieu of corporate income taxes. The Corporation claimed capital cost allowance and eligible capital expenditures totalling $116,350 (2006 - $138,425) in excess of amortization recorded to reduce the payment in lieu of corporate income taxes.

9. Payment in lieu of corporate income taxes (continued):

		2007		2006
Statutory rate	$	106,365	$	273,382
Tax effect of expenses that are not deductible for income tax purposes		1,281		2,991
Tax effect of differences in the timing of deductibility of items for payments in lieu of income taxes		(32,276)		(46,598)
	$	75,370	$	229,775

10. Employee future benefits:

(a) The Corporation is a member of the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan. The plan is a defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees, based on the length of service and rates of pay.

Contributions made during the period amount to $93,237 (2006 - $93,829).

(b) The Corporation has an unfunded defined benefit plan providing post-retirement health care benefits. The balance sheet includes a provision for the projected post-retirement benefit cost of $45,000 (2006 - $60,000).

11. Lease commitments:

The Corporation leases its premises in Pembroke, Ontario, from the Corporation of The City of Pembroke under the terms of a ten-year operating lease at an annual rental of $12. The lease contains an option which allows the lessee to purchase the property on or before December 1, 2009, at a cost of three hundred and sixty thousand, five hundred and eighty three dollars ($360,583) together with any assessable environmental clean-up costs.

The Corporation leases office premises from Mississippi River Power Corporation under the terms of an operating lease at a monthly cost of $998. The lease has no termination date.

The Corporation leases substation premises from Mississippi River Power Corporation under the terms of a two-year operating lease at a monthly cost of $275. The lease expires September 30, 2008.

The Corporation leases garage premises from the Corporation of the Town of Mississippi Mills under the terms of an operating lease at an annual rental of $1. The lease expires September 30, 2008 with an option to renew for a further five year term.

12. Contingencies:

The Corporation is a member of the Municipal Electric 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 member electric utilities.

Insurance premiums charged to each municipal electric utility consist of a levy per thousand dollars of service revenue subject to a credit or surcharge based on each electric utility's claims experience. Effective January 1, 2001, coverage is provided to a level of $20 million per incident.

No provision has been made for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

13. Fair value of instruments:

The carrying values of cash and cash equivalents, accounts receivable, cash and cash equivalents held for long-term customer deposits and vested sick leave, cash and cash equivalents held for regulatory liability, accounts payable and accrued liabilities approximate fair market value because of the short maturity of these instruments.

As the notes payable in the amount of $5,585,838 do not trade on the public markets, no fair value information is available. The notes payable bear interest at fixed rates and consequently the long-term debt risk exposure is minimal.

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. Cash and cash equivalents include amounts held for customer deposits and temporary investments amounting to $230,688. These temporary investments are of a short maturity with financial institutions with established credit ratings.

The Corporation earns its revenues from a broad base of customers located principally in Pembroke, Beachburg, Killaloe and Mississippi Mills. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

14. Energy purchase:

The Corporation is dependent on Hydro One for a significant portion of the electricity it purchases. The amount owing to Hydro One at December 31, 2007 is $3,547,254, (2006 - $2,040,896). Included in cost of power in the statement of earnings is $9,828,931 (2006 - $7,062,809) purchased from Hydro One.

15. Other operating revenue:

		2007		2006
Late payment charges	$	30,603	$	25,610
Property and equipment rent		41,056		55,378
Change of occupancy and connection fees		48,540		38,620
Labour on customer premises		81,317		76,170
Interest		257,105		214,836
Interest - Ottawa River Energy Solutions Inc.		24,447		28,741
	$	483,068	$	439,355

16. Comparative figures:

Certain of the 2006 comparative figures have been reclassified to conform with the financial presentation adopted in 2007.

Attachment 2 (of 3):

2008 Audited Statements with 2007 comparative information

Financial Statements of

OTTAWA RIVER POWER CORPORATION

Year ended December 31, 2008

SCOTT ROSIEN & DEMPSEY

Chartered Accountants

D.M. Scott, C.A.
D.W. Rosien, C.A.
W.T. Dempsey, C.A.

545 Pembroke Street West
Pembroke, Ontario K8A 5P2

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AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheet of Ottawa River Power Corporation as at December 31, 2008 and the statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Scott Rosien & Dempsey

Chartered Accountants
Licensed Public Accountants

Pembroke, Ontario
March 23, 2009

OTTAWA RIVER POWER CORPORATION

(Incorporated under the laws of Ontario)
Balance Sheet

December 31, 2008, with comparative figures for 2007

	2008	2007
Assets		
Current assets:		
Cash and cash equivalents	$ 4,517,081	$ 5,203,793
Accounts receivable (note 2)	1,052,823	1,286,958
Amounts in lieu of income taxes recoverable	6,112	75,124
Due from Ottawa River Energy Solutions Inc. (note 3)	692,310	292,487
Unbilled revenue	2,685,541	2,587,439
Inventory (note 4)	521,185	540,093
Prepaid expenses	230,634	129,532
	9,705,686	10,115,426
Restricted cash and cash equivalents:		
Cash and cash equivalents, held for customer deposits	134,247	115,344
Cash and cash equivalents, held for regulatory liability	2,968,456	2,381,507
	3,102,703	2,496,851
Property, plant and equipment (note 5):		
Land, building, distribution and office equipment and motor vehicles	23,170,452	22,714,217
Accumulated amortization	14,769,052	14,196,879
	8,401,400	8,517,338
	$ 21,209,789	$ 21,129,615

		2008		2007

Liabilities and Shareholders' Equity

Current liabilities:				
Accounts payable and accrued liabilities	$	4,635,741	$	5,002,229
Current portion of long-term debt		134,247		115,344
		4,769,988		5,117,573
Regulatory liability (note 6)		2,968,456		2,381,507
Long-term debt (note 7)		5,765,085		5,746,182
Shareholders' equity:				
Capital stock				
Authorized:				
Unlimited number of non-cumulative special shares				
Unlimited number of common shares				
Issued (note 8):				
5,568 Common shares		5,585,838		5,585,838
Retained earnings		2,120,422		2,298,515
		7,706,260		7,884,353
Lease commitments (note 11)				
Contingencies (note 12)				
	$	21,209,789	$	21,129,615

See accompanying notes to financial statements.

On behalf of the Board:

________________________ Director

________________________ Director

OTTAWA RIVER POWER CORPORATION

Statement of Earnings

Year ended December 31, 2008, with comparative figures for 2007

	2008	2007
Service revenue:		
Residential	$ 7,986,215	$ 7,649,827
General	10,009,256	10,513,896
Street lighting	231,707	250,801
	18,227,178	18,414,524
Cost of power	14,735,276	14,954,963
	3,491,902	3,459,561
Other operating revenue (note 15)	524,444	483,068
	4,016,346	3,942,629
Operating and maintenance expenses:		
Distribution	893,322	809,070
Utilization	77,269	57,886
Billing and collecting	680,124	530,896
General and administrative	727,544	938,580
Capital tax	12,453	22,850
Amortization	706,600	693,825
Interest on long-term debt	404,973	404,973
Interest on regulatory liability	111,141	101,121
	3,613,426	3,559,201
Earnings before amounts in lieu of income taxes	402,920	383,428
Amount in lieu of income taxes (note 9)	79,893	75,370
Net earnings	$ 323,027	$ 308,058

See accompanying notes to financial statements.

OTTAWA RIVER POWER CORPORATION

Statement of Retained Earnings

Year ended December 31, 2008, with comparative figures for 2007

	2008	2007
Retained earnings, beginning of year	$ 2,298,515	$ 2,380,217
Net earnings	323,027	308,058
Dividends paid	(501,120)	(389,760)
Retained earnings, end of year	$ 2,120,422	$ 2,298,515

See accompanying notes to financial statements.

OTTAWA RIVER POWER CORPORATION

Statement of Cash Flows

Year ended December 31, 2008, with comparative figures for 2007

	2008	2007
Cash provided by (used in):		
Operations:		
Cash received from customers	$ 18,197,917	$ 18,338,652
Cash paid to suppliers and employees	(17,480,250)	(15,323,857)
Interest earned	276,540	281,553
Interest paid	(516,114)	(506,094)
Corporate income and capital taxes paid	(23,334)	(209,495)
	454,759	2,580,759
Financing:		
Dividends paid	(501,120)	(389,760)
Investments:		
Customer deposits and post retirement benefits	18,903	(24,821)
Proceeds on disposal of equipment	20,600	-
Additions to property, plant and equipment	(679,854)	(819,035)
	(640,351)	(843,856)
Increase (decrease) in cash	(686,712)	1,347,143
Cash and cash equivalents, beginning of year	5,203,793	3,856,650
Cash and cash equivalents, end of year	$ 4,517,081	$ 5,203,793

See accompanying notes to financial statements.

Ottawa River Power Corporation (the "Corporation") was incorporated under the Business Corporations Act (Ontario) on April 22, 1999. Ottawa River Power Corporation is the successor to the former Pembroke Hydro Electric Commission ("Pembroke Hydro"), the Beachburg Hydro System ("Beachburg Hydro"), the Township of Killaloe, Haggarty & Richards Hydro Electric Commission ("Killaloe Hydro") and the Town of Mississippi Mills Public Utilities Commission ("Almonte Hydro"). The Corporation is the electric distribution utility for residents of the City of Pembroke, the Village of Beachburg, the Township of Killaloe and the Town of Mississippi Mills (Almonte Ward).

1. Significant accounting policies:

(a) Basis of presentation:

The financial statements of the Ottawa River Power Corporation are the representation of management prepared in accordance with Canadian generally accepted accounting principles and accounting guidance provided by its regulator, the Ontario Energy Board ("OEB"), as contained in its Accounting Procedures Handbook, under the authority of the Ontario Energy Board Act, 1998.

(b) Rate setting:

Ottawa River Power 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.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in the change in the timing of accounting recognition from that which would have applied in an unregulated company. Specifically, the following accounting treatments have been applied:

(i) Capital and operating costs incurred in respect of the transition to competitive markets have been deferred with amortization to commence at a date that a rate increase is implemented to offset the amortization of the transition costs. In November 2003, the Province of Ontario introduced the Ontario Energy Board Amendment Act (Electricity Pricing) 2003 (the "2003 Act"). The 2003 Act will impact both the distribution and energy rates charged to customers and includes a provision for the recovery of regulatory assets (note 1(j)).

(ii) An amount to represent the cost of funds used during construction and development has been applied based on the value of construction in progress.

(iii) The Corporation provides for amounts in lieu of corporate income taxes using the taxes payable method for its regulated business activities.

1. Significant accounting policies (continued):

(iv) The Corporation has deferred certain pre-market opening cost of power variances and post-market opening retail settlement variances in accordance with Article 490 of the OEB's Accounting Procedures Handbook.

(c) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

(d) Revenue recognition:

Revenue from the sale of electricity is recognized on the accrual basis, which includes an estimate of unbilled revenue which represents electricity consumed by customers since the date of each customer's last meter reading. Actual results could differ from estimates made of electricity usage. The related cost of power is recorded on the basis of power used.

Labour on customer premises is generally short-term in nature. Revenue is recognized in the period the work is completed.

Interest is recognized on the accrual basis.

(e) Measurement uncertainty:

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered and include an appropriate allowance for unrecoverable amounts. Inventories are recorded net of provisions for obsolescence.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

(f) Inventory:

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031 - "Inventories" which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to

1. Significant accounting policies (continued):

net realizable value. The implementation of this standard did not have any impact on the Corporation's results of operations.

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on the lower of a weighted-moving average basis or replacement cost. The Corporation has retrospectively reclassified all major future components of its electricity distribution system infrastructure from inventory to property, plant and equipment. Once capitalized, these items are not amortized until they are put into service.

(g) Property, plant and equipment:

Capital assets are recorded at cost and include contracted services, materials, labour, engineering costs, overheads and an allowance for the cost of funds used during construction when applied. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be 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 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.

Amortization of capital asset values is charged to operations on a straight-line basis over their estimated service lives as follows:

	Estimated service life	
	Range	Average
Land rights	25 to 30 years	30
Buildings	30 to 60 years	50
Poles, towers and fixtures	25 to 40 years	25
Overhead conductors and devices	25 to 40 years	25
Underground conduit	25 to 40 years	25
Underground conductors and devices	25 to 40 years	25
Services	3 to 10 years	5

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be

1. Significant accounting policies (continued):

constructed.

An allowance for the cost of funds used during the construction period may be applied. The rate applied is equal to the rate allowed by the OEB in respect of long-term borrowings, being 6.9%.

(h) Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits and invested in term deposits, which are reported separately from the Corporation's own cash and cash equivalents. Interest is paid on customer balances at rates established from time to time by the Corporation.

(i) Pension and other post-employment benefits:

The Corporation accounts for its participation in the Ontario Municipal Employees Retirement Funds ("OMERS"), a multi-employer public sector pension funds, as a defined contribution plan.

The Corporation 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.

(j) Regulatory assets and liabilities:

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in rates. Regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding regulated retail transmission, wholesale market, and cost of power rates charged to the utility. The OEB directs the distribution utilities to defer these variances for future true-up with the Independent Electricity Systems Operator ("IESO").

Post market-opening retail settlement variances are variances that occur between the amount charged by Hydro One to Ottawa River Power Corporation and the amounts collected from customers. These include the cost of power, as well as the wholesale market settlement charge and retail transmission charges. The variances incurred up to December 31, 2004 have been recovered in rates up to April 30, 2008. The variances incurred from January 1, 2005 onward will be disposed of in a future proceeding and are reflected separately on the Corporation's balance sheet until the manner and timing of disposition is determined by the

1. Significant accounting policies (continued):

OEB.

In 2005 a new price plan for residential, low-volume and designated electricity consumers was introduced. At the request of the Minister of Energy, the Ontario Energy Board developed an electricity price plan that provides stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators. Effective Nov 1, 2008, eligible consumers pay 5.6 cents per kilowatt hour (kWh) up to a certain threshold each month and 6.5 cents per kWh for electricity used per month over this amount. This amount is reflected on the "Electricity" line on consumers' bills.

The price threshold - the amount of electricity that is charged at the lower price - changes twice a year for residential consumers. The price threshold will be 600 kWh per month in the summer (May 1st to October 31st) and 1,000 kWh per month in the winter (November 1st to April 30th). Prices are reviewed and may change every six months based on an updated Ontario Energy Board forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous period.

Management continues to believe that it is probable the regulatory assets will be fully recovered. In the event that recovery from future rates is no longer considered probable or portions of those amounts deferred are determined not to be recoverable, such amounts will be expensed in the period this determination is made.

(k) Corporate income and capital taxes:

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in The Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations.

The Corporation provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes.

(l) Financial instruments:

The Corporation has classified its cash as financial assets held-for-trading. The remainder of the Corporation's financial assets are classified as loans and receivables. Loans and receivables and all financial liabilities are carried at amortized cost using the effective interest rate method.

2. Accounts receivable:

		2008		2007
Residential and commercial energy and rentals	$	866,730	$	1,115,459
Work at customers premises		183,583		112,634
Municipal street lights		-		4,636
Employee purchases		3,547		3,739
Due from Brascan Energy Marketing Inc.		-		25,565
GST receivable		68,963		94,925
		1,122,823		1,356,958
Allowance for doubtful accounts		(70,000)		(70,000)
	$	1,052,823	$	1,286,958

3. Related party transactions:

(a) Ottawa River Energy Solutions Inc.

						2008		2007
		Capital Project		Operating Loan		Total		Total
Balance, January 1	$	-	$	292,487	$	292,487	$	431,376
Advances during the year		493,725		54,819		548,544		78,635
Interest		1,440		10,643		12,083		24,447
Payments during the year		-		(160,804)		(160,804)		(241,971)
Balance, December 31	$	495,165	$	197,145	$	692,310	$	292,487

During the year the Corporation agreed to provide financing to Ottawa River Energy Solutions Inc. for a capital project up to $1,000,000 of which the Corporation has a registered general security agreement in the amount of $500,000 and $200,000 each of which expire on October 11, 2012 and September 27, 2009 respectively. Advances are due on demand. Interest is to be calculated semi-annually at 5.75% with the rate to be reviewed annually.

Interest on the operating loan is charged at the Royal Bank of Canada prime rate, calculated semi-annually and payable on April 30.

The Corporation provides services to Ottawa River Energy Solutions Inc., at cost. A summary of amounts charged by the Corporation to the Ottawa River Energy Solutions Inc. are as follows:

3. Related party transactions (continued):

		2008		2007
Labour on customer premises	$	32,105	$	22,359
Interest - Ottawa River Energy Solutions Inc.		12,083		24,447
	$	44,188	$	46,806

At December 31, 2008, there are no accounts payable and accrued liabilities due to Ottawa River Energy Solutions Inc. Ottawa River Energy Solutions Inc. is affiliated by virtue of common ownership.

(b) Corporation of the City of Pembroke

The Corporation provides electricity and services to the principal shareholder, the City of Pembroke. Electrical energy is sold to the City at the same prices and terms as other electricity customers consuming equivalent amounts of electricity. Street lighting maintenance services are provided at rates determined in relation to other service providers. Other construction services are provided at cost. A summary of amounts charged by the Corporation to the City of Pembroke are as follows:

		2008		2007
Electrical energy	$	632,906	$	632,867
Street lighting energy		195,894		205,000
Street light maintenance		37,956		32,863
Traffic light maintenance		-		4,076
	$	866,756	$	874,806

At December 31, 2008, there are no accounts payable and accrued liabilities due to the City of Pembroke and accounts receivable include $136,604, (2007 - $112,554) from the City of Pembroke.

4. Inventory:

Inventory consists of maintenance and construction materials amounting to $521,185 (2007 - $540,093). As a result of the adoption of CICA Handbook Section 3031 - "Inventories", $364,466 was reclassified out of inventory and into property, plant and equipment as at December 31, 2008 (2007 - $352,264).

5. Property, plant and equipment:

			2008	2007
	Cost	Accumulated amortization	Net book value	Net book value
Land and land rights	$ 141,308	$ 6,386	$ 134,922	$ 135,257
Buildings	447,221	240,338	206,883	188,090
Poles, towers and fixtures	7,935,543	5,149,669	2,785,874	2,919,536
Overhead conductors and devices	5,113,757	2,611,657	2,502,100	2,394,233
Underground conduit	2,635,137	1,823,822	811,315	971,725
Underground conductors and devices	2,813,214	1,756,941	1,056,273	1,121,610
Services	4,084,272	3,180,239	904,033	786,887
	$ 23,170,452	$ 14,769,052	$ 8,401,400	$ 8,517,338

During the year, no provision for the cost of funds used during construction was capitalized.

During the period, total amortization recorded as operating and maintenance expenses amounted to $788,567, (2007 - $757,389).

6. Regulatory liability:

It is expected that the Corporation will apply for, and receive, in its electricity rates an allowance to remit the remaining regulated liabilities and an allowance to recover the remaining regulatory assets (note 1(j)).

	2008	2007
Assets (liabilities):		
Regulatory assets recovery account	$ (108,090)	$ (102,897)
Settlement variances	(3,120,275)	(2,443,366)
Smart meters	152,484	57,331
Other	107,425	107,425
	$ (2,968,456)	$ (2,381,507)

7. Long-term debt:

	2008	2007
7.25% Promissory note payable to the Corporation of the City of Pembroke, due May 1, 2022	$ 4,364,000	$ 4,364,000
7.25% Promissory note payable to the Corporation of the Village of Beachburg, due May 1, 2022	147,000	147,000
7.25% Promissory note payable to the Corporation of the Township of Killaloe, Haggarty and Richards, due May 1, 2022	172,348	172,348
7.25% Promissory note payable to the Corporation of the Town of Mississippi Mills, due May 1, 2022	902,490	902,490
Customer deposits	268,494	230,688
Post-retirement benefits	45,000	45,000
	5,899,332	5,861,526
Current portion of long-term debt	134,247	115,344
	$ 5,765,085	$ 5,746,182

Interest on promissory notes is calculated annually and payable quarterly to the shareholders. The aggregate maturities of long-term debt for each of the two years subsequent to December 31, 2008 are as follows: 2009 - $134,237; and 2010 - $134,237.

8. Capital stock:

As at December 31, 2008, the common shares of the corporation are held as follows:

	Common Shares	Percentage Ownership
Corporation of the City of Pembroke	4,364	78.38%
Corporation of the Village of Beachburg	147	2.64%
Corporation of the Township of Killaloe, Haggarty and Richards	169	3.04%
Corporation of the Town of Mississippi Mills	888	15.94%
	5,568	100.00%

The common share ownership has not changed from prior year.

9. Payment in lieu of corporate income taxes:

The Corporation follows the taxes payable method of accounting for amounts paid in lieu of corporate income taxes. The Corporation claimed capital cost allowance and eligible capital expenditures totalling $92,547 (2007 - $116,350) in excess of amortization recorded to reduce the payment in lieu of corporate income taxes.

	2008	2007
Statutory rate	$ 103,716	$ 106,365
Tax effect of expenses that are not deductible for income tax purposes	-	1,281
Tax effect of differences in the timing of deductibility of items for payments in lieu of income taxes	(23,823)	(32,276)
	$ 79,893	$ 75,370

10. Employee future benefits:

(a) The Corporation is a member of the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan. The plan is a defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees, based on the length of service and rates of pay.

Contributions made during the period amount to $96,659 (2007 - $93,237).

(b) The Corporation has an unfunded defined benefit plan providing post-retirement health care benefits. The balance sheet includes a provision for the projected post-retirement benefit cost of $45,000 (2007 - $45,000).

11. Lease commitments:

11. Lease commitments (continued):

The Corporation leases its premises in Pembroke, Ontario, from the Corporation of The City of Pembroke under the terms of a ten-year operating lease at an annual rental of $12. The lease contains an option which allows the lessee to purchase the property on or before December 1, 2009, at a cost of three hundred and sixty thousand, five hundred and eighty three dollars ($360,583) together with any assessable environmental clean-up costs.

The Corporation leases office premises from Mississippi River Power Corporation under the terms of an operating lease at a monthly cost of $998. The lease has no termination date.

The Corporation leases substation premises from Mississippi River Power Corporation under the terms of a yearly operating lease at a monthly cost of $275. The lease expires September 30, 2009.

The Corporation leases garage premises from the Corporation of the Town of Mississippi Mills under the terms of an operating lease at an annual rental of $1. The lease expires September 30, 2013.

12. Contingencies:

(a) Insurance claims:

The Corporation is a member of the Municipal Electric 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 member electric utilities.

Insurance premiums charged to each municipal electric utility consist of a levy per thousand dollars of service revenue subject to a credit or surcharge based on each electric utility's claims experience. Effective January 1, 2001, coverage is provided to a level of $20 million per incident.

No provision has been made for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Other claims:

A class action claiming $500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

12. Contingencies (continued):

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on these financial statements.

13. Fair value of instruments:

The carrying values of cash and cash equivalents, accounts receivable, cash and cash equivalents held for long-term customer deposits and vested sick leave, cash and cash equivalents held for regulatory liability, accounts payable and accrued liabilities approximate fair market value because of the short maturity of these instruments.

As the notes payable in the amount of $5,585,838 do not trade on the public markets, no fair value information is available. The notes payable bear interest at fixed rates and consequently the long-term debt risk exposure is minimal.

Financial assets held by the Corporation expose it to credit risk. As at December 31, 2008, there were no significant concentrations of credit risk with respect to any class of financial assets. Cash and cash equivalents include amounts held for customer deposits and temporary investments amounting to $268,494. These temporary investments are of a short maturity with financial institutions with established credit ratings.

The Corporation earns its revenues from a broad base of customers located principally in Pembroke, Beachburg, Killaloe and Mississippi Mills. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

It is management's opinion that the facility is not exposed to significant interest, currency or credit risks arising from its financial instruments.

14. Energy purchase:

The Corporation is dependent on Hydro One for a significant portion of the electricity it purchases. The amount owing to Hydro One at December 31, 2008 is $2,994,675, (2007 - $3,547,254). Included in cost of power in the statement of earnings is $8,102,720 (2007 - $9,828,931) purchased from Hydro One.

15. Other operating revenue:

15. Other operating revenue (continued):

	2008	2007
Late payment charges	$ 27,322	$ 30,603
Property and equipment rent	41,817	41,056
Change of occupancy and connection fees	42,945	48,540
Labour on customer premises	123,165	81,317
Interest	263,737	257,105
Interest - Ottawa River Energy Solutions Inc.	12,083	24,447
Gain on disposal of capital assets	13,375	-
	$ 524,444	$ 483,068

16. Bank indebtedness, bankers' acceptances and letters of credit:

The Corporation has a bilateral demand line of credit for $1,000,000 with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate. At December 31, 2008, no amounts had been drawn on the line of credit (2007 - $nil).

17. Comparative figures:

Certain of the 2007 comparative figures have been reclassified to conform with the financial presentation adopted in 2008.

Attachment 3 (of 3):

2009 Audited Statements with 2008 comparative information

Financial Statements of

OTTAWA RIVER POWER CORPORATION

Year ended December 31, 2009

SCOTT ROSIEN & DEMPSEY

Chartered Accountants

D.M. Scott, C.A.
D.W. Rosien, C.A.
W.T. Dempsey, C.A.

545 Pembroke Street West
Pembroke, Ontario K8A 5P2

TELEPHONE: 613-735-3981
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AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheet of Ottawa River Power Corporation as at December 31, 2009 and the statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Scott Rosien Dempsey

Chartered Accountants
Licensed Public Accountants

Pembroke, Ontario
March 30, 2010

OTTAWA RIVER POWER CORPORATION

(Incorporated under the laws of Ontario)
Balance Sheet

December 31, 2009, with comparative figures for 2008

Assets

	2009	2008
Current assets:		
Cash and cash equivalents	$ 2,632,757	$ 4,392,878
Accounts receivable (note 2)	1,356,295	1,052,823
Amounts in lieu of income taxes recoverable	5,708	6,112
Due from Ottawa River Energy Solutions Inc. (note 3)	589,521	692,310
Unbilled revenue	2,561,140	2,685,541
Inventory (note 4)	474,386	521,185
Prepaid expenses	231,842	230,634
	7,851,649	9,581,483
Restricted cash and cash equivalents:		
Cash and cash equivalents, held for customer deposits	106,246	134,247
Cash and cash equivalents, held for regulatory liability	4,583,331	3,092,659
	4,689,577	3,226,906
Property, plant and equipment (note 5):		
Land, building, distribution and office equipment and motor vehicles	23,897,188	23,170,452
Accumulated amortization	15,387,718	14,769,052
	8,509,470	8,401,400
Future income tax assets (note 1(k))	861,382	-
	$ 21,912,078	$ 21,209,789

		2009		2008

Liabilities and Shareholders' Equity

Current liabilities:				
Accounts payable and accrued liabilities	$	3,898,327	$	4,511,538
Current portion of long-term debt		106,247		134,247
		4,004,574		4,645,785
Regulatory liability (note 6)		4,583,331		3,092,659
Long-term debt (note 7)		5,737,084		5,765,085
Shareholders' equity:				
Capital stock				
Authorized:				
Unlimited number of non-cumulative special shares				
Unlimited number of common shares				
Issued (note 8):				
5,568 Common shares		5,585,838		5,585,838
Retained earnings		2,001,251		2,120,422
		7,587,089		7,706,260
Commitments (note 11)				
Contingencies (note 12)				
	$	21,912,078	$	21,209,789

See accompanying notes to financial statements.

On behalf of the Board:

_______________________ Director

_______________________ Director

OTTAWA RIVER POWER CORPORATION

Statement of Earnings

Year ended December 31, 2009, with comparative figures for 2008

	2009	2008
Service revenue:		
Residential	$ 6,856,184	$ 7,608,551
General	10,634,721	9,788,395
Street lighting	291,581	231,827
	17,782,486	17,628,773
Cost of power	14,257,639	14,136,871
	3,524,847	3,491,902
Other operating revenue (note 15)	468,114	524,444
Interest on regulatory asset	19,032	32,766
	4,011,993	4,049,112
Operating and maintenance expenses:		
Distribution	977,908	893,322
Utilization	50,795	77,269
Billing and collecting	688,051	680,124
General and administrative	699,529	727,544
Capital tax	9,113	12,453
Amortization	696,514	706,600
Interest on long-term debt	404,973	404,973
Interest on regulatory liability	67,198	143,907
	3,594,081	3,646,192
Earnings before amounts in lieu of income taxes	417,912	402,920
Amount in lieu of income taxes (note 9)	63,803	79,893
Net earnings	$ 354,109	$ 323,027

See accompanying notes to financial statements.

OTTAWA RIVER POWER CORPORATION

Statement of Retained Earnings

Year ended December 31, 2009, with comparative figures for 2008

		2009		2008
Retained earnings, beginning of year	$	2,120,422	$	2,298,515
Net earnings		354,109		323,027
Dividends paid		(473,280)		(501,120)
Retained earnings, end of year	$	2,001,251	$	2,120,422

See accompanying notes to financial statements.

OTTAWA RIVER POWER CORPORATION

Statement of Cash Flows

Year ended December 31, 2009, with comparative figures for 2008

	2009	2008
Cash provided by (used in):		
Operations:		
Cash received from customers	$ 18,006,406	$ 17,599,512
Cash paid to suppliers and employees	(17,161,604)	(16,881,845)
Interest earned	186,944	309,306
Interest paid	(472,171)	(548,880)
Corporate income and capital taxes paid	(72,512)	(23,334)
	487,063	454,759
Financing:		
Dividends paid	(473,280)	(501,120)
Investments:		
Customer deposits and post retirement benefits	(28,000)	18,903
Restricted cash	(861,382)	-
Proceeds on disposal of equipment	92,390	20,600
Additions to property, plant and equipment	(976,912)	(679,854)
	(1,773,904)	(640,351)
Decrease in cash	(1,760,121)	(686,712)
Cash and cash equivalents, beginning of year	4,392,878	5,079,590
Cash and cash equivalents, end of year	$ 2,632,757	$ 4,392,878

See accompanying notes to financial statements.

Ottawa River Power Corporation (the "Corporation") was incorporated under the Business Corporations Act (Ontario) on April 22, 1999. Ottawa River Power Corporation is the successor to the former Pembroke Hydro Electric Commission ("Pembroke Hydro"), the Beachburg Hydro System ("Beachburg Hydro"), the Township of Killaloe, Haggarty & Richards Hydro Electric Commission ("Killaloe Hydro") and the Town of Mississippi Mills Public Utilities Commission ("Almonte Hydro"). The Corporation is the electric distribution utility for residents of the City of Pembroke, the Village of Beachburg, the Township of Killaloe and the Town of Mississippi Mills (Almonte Ward).

1. Significant accounting policies:

(a) Basis of presentation:

The financial statements of the Ottawa River Power Corporation are the representation of management prepared in accordance with Canadian generally accepted accounting principles and accounting guidance provided by its regulator, the Ontario Energy Board ("OEB"), as contained in its Accounting Procedures Handbook, under the authority of the Ontario Energy Board Act, 1998.

(b) Rate setting:

Ottawa River Power 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.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in the change in the timing of accounting recognition from that which would have applied in an unregulated company. Specifically, the following accounting treatments have been applied:

(i) Capital and operating costs incurred in respect of the transition to competitive markets have been deferred with amortization to commence at a date that a rate increase is implemented to offset the amortization of the transition costs. In November 2003, the Province of Ontario introduced the Ontario Energy Board Amendment Act (Electricity Pricing) 2003 (the "2003 Act"). The 2003 Act will impact both the distribution and energy rates charged to customers and includes a provision for the recovery of regulatory assets (note 1(j)).

(ii) An amount to represent the cost of funds used during construction and development has been applied based on the value of construction in progress.

(iii) The Corporation provides for amounts in lieu of corporate income taxes using the liability method for its regulated business activities.

1. Significant accounting policies (continued):

(iv) The Corporation has deferred certain pre-market opening cost of power variances and post-market opening retail settlement variances in accordance with Article 490 of the OEB's Accounting Procedures Handbook.

(c) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

(d) Revenue recognition:

Revenue from the sale of electricity is recognized on the accrual basis, which includes an estimate of unbilled revenue which represents electricity consumed by customers since the date of each customer's last meter reading. Actual results could differ from estimates made of electricity usage. The related cost of power is recorded on the basis of power used.

Labour on customer premises is generally short-term in nature. Revenue is recognized in the period the work is completed.

Interest is recognized on the accrual basis.

(e) Measurement uncertainty:

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered and include an appropriate allowance for unrecoverable amounts. Inventories are recorded net of provisions for obsolescence.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

(f) Inventory:

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031 - "Inventories" which is based on the International Accounting Standards Board's International Accounting Standard 2 and replaced existing CICA Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to

1. **Significant accounting policies (continued):**

net realizable value. The implementation of this standard did not have any impact on the Corporation's results of operations.

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on the lower of a weighted-moving average basis or replacement cost. The Corporation has retrospectively reclassified all major future components of its electricity distribution system infrastructure from inventory to property, plant and equipment. Once capitalized, these items are not amortized until they are put into service.

(g) Property, plant and equipment:

Capital assets are recorded at cost and include contracted services, materials, labour, engineering costs, overheads and an allowance for the cost of funds used during construction when applied. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be 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 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.

Amortization of capital asset values is charged to operations on a straight-line basis over their estimated service lives as follows:

	Estimated service life	
	Range	Average
Land rights	25 to 30 years	30
Buildings	30 to 60 years	50
Poles, towers and fixtures	25 to 40 years	25
Overhead conductors and devices	25 to 40 years	25
Underground conduit	25 to 40 years	25
Underground conductors and devices	25 to 40 years	25
Services	3 to 10 years	5

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be

1. Significant accounting policies (continued):

constructed.

An allowance for the cost of funds used during the construction period may be applied. The rate applied is equal to the rate allowed by the OEB in respect of long-term borrowings, being 6.9%.

(h) Customer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits and invested in term deposits, which are reported separately from the Corporation's own cash and cash equivalents. Interest is paid on customer balances at rates established from time to time by the Corporation.

(i) Pension and other post-employment benefits:

The Corporation accounts for its participation in the Ontario Municipal Employees Retirement Funds ("OMERS"), a multi-employer public sector pension funds, as a defined contribution plan.

The Corporation 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.

(j) Regulatory assets and liabilities:

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in rates. Regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding regulated retail transmission, wholesale market, and cost of power rates charged to the utility. The OEB directs the distribution utilities to defer these variances for future true-up with the Independent Electricity Systems Operator ("IESO").

Post market-opening retail settlement variances are variances that occur between the amount charged by Hydro One to Ottawa River Power Corporation and the amounts collected from customers. These include the cost of power, as well as the wholesale market settlement charge and retail transmission charges. The variances incurred up to December 31, 2004 have been recovered in rates up to April 30, 2008. The variances incurred from January 1, 2005 onward will be disposed of in a future proceeding and are reflected separately on the Corporation's balance sheet until the manner and timing of disposition is determined by the

1. Significant accounting policies (continued):

OEB.

The future income taxes regulatory liability relates to the expected future electricity distribution rate reduction for customers arising from timing differences in the recognition of future tax assets. On January 1, 2009, the Corporation began to account for the differences between its financial statement carrying value and tax basis of assets and liabilities following the liability method in accordance with CICA Handbook Section 3465.

In 2005 a new price plan for residential, low-volume and designated electricity consumers was introduced. At the request of the Minister of Energy, the Ontario Energy Board developed an electricity price plan that provides stable and predictable electricity pricing, encourages conservation and ensures the price consumers pay for electricity better reflects the price paid to generators. Effective Nov 1, 2008, eligible consumers pay 5.6 cents per kilowatt hour (kWh) up to a certain threshold each month and 6.5 cents per kWh for electricity used per month over this amount. This amount is reflected on the "Electricity" line on consumers' bills.

The price threshold - the amount of electricity that is charged at the lower price - changes twice a year for residential consumers. The price threshold will be 600 kWh per month in the summer (May 1st to October 31st) and 1,000 kWh per month in the winter (November 1st to April 30th). Prices are reviewed and may change every six months based on an updated Ontario Energy Board forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous period.

Management continues to believe that it is probable the regulatory assets will be fully recovered. In the event that recovery from future rates is no longer considered probable or portions of those amounts deferred are determined not to be recoverable, such amounts will be expensed in the period this determination is made.

(k) Corporate income and capital taxes:

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in The Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations.

The Corporation provided for payments in lieu of corporate income taxes using the taxes payable method until December 31, 2008. Effective January 1, 2009 the Corporation began using the liability method of accounting following the new recommendations from the CICA and the OEB.

1. Significant accounting policies (continued):

Under the taxes payable method, no provisions were made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes became payable, it was expected that they would be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time.

Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arise from temporary differences between the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

(l) Financial instruments:

The Corporation has classified its cash as financial assets held-for-trading. The remainder of the Corporation's financial assets are classified as loans and receivables. Loans and receivables and all financial liabilities are carried at amortized cost using the effective interest rate method.

2. Accounts receivable:

	2009	2008
Residential and commercial energy and rentals	$ 1,278,932	$ 866,730
Work at customers premises	82,514	183,583
Municipal street lights	8,731	-
Employee purchases	3,887	3,547
GST receivable	53,926	68,963
Other miscellaneous receivables	3,305	-
	1,431,295	1,122,823
Allowance for doubtful accounts	(75,000)	(70,000)
	$ 1,356,295	$ 1,052,823

3. Related party transactions:

(a) Ottawa River Energy Solutions Inc.

					2009		2008
		Capital Project		Operating Loan		Total		Total
Balance, January 1	$	495,165	$	197,145	$	692,310	$	292,487
Advances during the year		161,325		186,151		347,476		548,544
Interest		19,950		7,478		27,428		12,083
Payments during the year		(477,693)		-		(477,693)		(160,804)
Balance, December 31	$	198,747	$	390,774	$	589,521	$	692,310

The Corporation agreed to provide financing to Ottawa River Energy Solutions Inc. for a capital project up to $1,000,000 of which the Corporation has a registered general security agreement in the amount of $500,000 which expires on October 11, 2012. Advances are due on demand. Interest is to be calculated semi-annually at 5.75% with the rate to be reviewed annually.

Interest on the operating loan is charged at the Royal Bank of Canada prime rate, calculated semi-annually and payable on April 30.

The Corporation provides services to Ottawa River Energy Solutions Inc., at cost. A summary of amounts charged by the Corporation to the Ottawa River Energy Solutions Inc. are as follows:

		2009		2008
Labour on customer premises	$	32,664	$	32,105
Interest - Ottawa River Energy Solutions Inc.		27,428		12,083
	$	60,092	$	44,188

At December 31, 2009, there are no accounts payable and accrued liabilities due to Ottawa River Energy Solutions Inc. Ottawa River Energy Solutions Inc. is affiliated by virtue of common ownership.

(b) Corporation of the City of Pembroke

The Corporation provides electricity and services to the principal shareholder, the City of Pembroke. Electrical energy is sold to the City at the same prices and terms as other electricity customers consuming equivalent amounts of electricity. Street lighting maintenance services are provided at rates determined in relation to other service providers. Other

3. Related party transactions (continued):

construction services are provided at cost. A summary of amounts charged by the Corporation to the City of Pembroke are as follows:

	2009	2008
Electrical energy	$ 600,856	$ 632,906
Street lighting energy	208,409	195,894
Street light maintenance	51,655	37,956
	$ 860,920	$ 866,756

At December 31, 2009, there are no accounts payable and accrued liabilities due to the City of Pembroke and accounts receivable include $127,526, (2008 - $136,604) from the City of Pembroke.

4. Inventory:

Inventory consists of maintenance and construction materials amounting to $474,386 (2008 - $521,185).

5. Property, plant and equipment:

			2009	2008
	Cost	Accumulated amortization	Net book value	Net book value
Land and land rights	$ 141,308	$ 6,721	$ 134,587	$ 134,922
Buildings	453,550	247,903	205,647	206,883
Poles, towers and fixtures	8,492,210	5,387,441	3,104,769	2,785,874
Overhead conductors and devices	5,442,653	2,796,107	2,646,546	2,502,100
Underground conduit	2,635,191	1,920,613	714,578	811,315
Underground conductors and devices	2,936,238	1,867,919	1,068,319	1,056,273
Services	3,796,038	3,161,014	635,024	904,033
	$ 23,897,188	$ 15,387,718	$ 8,509,470	$ 8,401,400

During the year, no provision for the cost of funds used during construction was capitalized.

During the period, total amortization recorded as operating and maintenance expenses amounted

5. Property, plant and equipment (continued):

to $776,452, (2008 - $788,567).

6. Regulatory liability:

It is expected that the Corporation will apply for, and receive, in its electricity rates an allowance to remit the remaining regulated liabilities and an allowance to recover the remaining regulatory assets (note 1(j)).

	2009	2008
Assets (liabilities):		
Regulatory assets recovery account	$ (106,866)	$ (108,090)
Settlement variances	(4,474,123)	(3,244,478)
Smart meters	747,371	152,484
Other	111,669	107,425
Future income taxes	(861,382)	-
	$ (4,583,331)	$ (3,092,659)

7. Long-term debt:

	2009	2008
7.25% Promissory note payable to the Corporation of the City of Pembroke, due May 1, 2022	$ 4,364,000	$ 4,364,000
7.25% Promissory note payable to the Corporation of the Village of Beachburg, due May 1, 2022	147,000	147,000
7.25% Promissory note payable to the Corporation of the Township of Killaloe, Haggarty and Richards, due May 1, 2022	172,348	172,348
7.25% Promissory note payable to the Corporation of the Town of Mississippi Mills, due May 1, 2022	902,490	902,490
Customer deposits	212,493	268,494
Post-retirement benefits	45,000	45,000
	5,843,331	5,899,332
Current portion of long-term debt	106,247	134,247
	$ 5,737,084	$ 5,765,085

Interest on promissory notes is calculated annually and payable quarterly to the shareholders. The aggregate maturities of long-term debt for each of the two years subsequent to December 31, 2009 are as follows: 2010 - $106,247; and 2011 - $106,247.

8. Capital stock:

As at December 31, 2009, the common shares of the corporation are held as follows:

	Common Shares	Percentage Ownership
Corporation of the City of Pembroke	4,364	78.38%
Corporation of the Village of Beachburg	147	2.64%
Corporation of the Township of Killaloe, Haggarty and Richards	169	3.04%
Corporation of the Town of Mississippi Mills	888	15.94%
	5,568	100.00%

The common share ownership has not changed from prior year.

9. Payment in lieu of corporate income taxes:

On January 1, 2009, the Corporation began to account for the differences between its financial statement carrying value and tax basis of assets and liabilities following the liability method in accordance with CICA Handbook Section 3465 (note 1(k)). As at December 31, 2009, the Corporation has recorded a future income tax asset of $861,382 and a corresponding regulatory liability of $861,382.

The Corporation claimed capital cost allowance and eligible capital expenditures totalling $148,159 (2008 - $92,547) in excess of amortization recorded to reduce the payment in lieu of corporate income taxes.

	2009	2008
Statutory rate	$ 98,563	$ 103,716
Tax effect of expenses that are not deductible for income tax purposes	183	-
Tax effect of differences in the timing of deductibility of items for payments in lieu of income taxes	(34,943)	(23,823)
	$ 63,803	$ 79,893

10. Employee future benefits:

(a) The Corporation is a member of the Ontario Municipal Employers Retirement Fund (OMERS), which is a multi-employer plan. The plan is a defined benefit plan, which specifies the amount of the retirement benefit to be received by the employees, based on the length of service and rates of pay.

Contributions made during the period amount to $103,140 (2008 - $96,659).

(b) The Corporation has an unfunded defined benefit plan providing post-retirement health care benefits. The balance sheet includes a provision for the projected post-retirement benefit cost of $45,000 (2008 - $45,000).

11. Commitments:

The Corporation leases its premises in Pembroke, Ontario, from the Corporation of The City of Pembroke under the terms of a ten-year operating lease at an annual rental of $12. The lease contained an option which allowed the lessee to purchase the property on or before December 1, 2009, at a cost of three hundred and sixty thousand, five hundred and eighty three dollars ($360,583) together with any assessable environmental clean-up costs. The Corporation is currently in discussions with the Corporation of the City of Pembroke regarding the status of this lease.

The Corporation leases office premises from Mississippi River Power Corporation under the terms of an operating lease at a monthly cost of $998. The lease has no termination date.

The Corporation leases substation premises from Mississippi River Power Corporation under the terms of a yearly operating lease at a monthly cost of $275. The lease expires September 30, 2010.

The Corporation leases garage premises from the Corporation of the Town of Mississippi Mills under the terms of an operating lease at an annual rental of $1. The lease expires September 30, 2013.

The Corporation has committed to purchasing a new vehicle costing $263,538 and expects to take delivery in 2010.

12. Contingencies:

(a) Insurance claims:

The Corporation is a member of the Municipal Electric 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 member electric utilities.

12. Contingencies (continued):

Insurance premiums charged to each municipal electric utility consist of a levy per thousand dollars of service revenue subject to a credit or surcharge based on each electric utility's claims experience. Effective January 1, 2001, coverage is provided to a level of $20 million per incident.

No provision has been made for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Late payment charges class action:

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 defenses 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 Supreme 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 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. The parties are in settlement discussions but no settlement has been reached.

12. Contingencies (continued):

The proposed settlement, subject to unanimous approval by LDCs, places the Corporation's liability at $28,562. The amount, once approved, will be recorded as an expense in the period it is paid.

13. Fair value of instruments:

The carrying values of cash and cash equivalents, accounts receivable, cash and cash equivalents held for long-term customer deposits and vested sick leave, cash and cash equivalents held for regulatory liability, accounts payable and accrued liabilities approximate fair market value because of the short maturity of these instruments.

As the notes payable in the amount of $5,585,838 do not trade on the public markets, no fair value information is available. The notes payable bear interest at fixed rates and consequently the long-term debt risk exposure is minimal.

Financial assets held by the Corporation expose it to credit risk. As at December 31, 2009, there were no significant concentrations of credit risk with respect to any class of financial assets. Cash and cash equivalents include amounts held for customer deposits and temporary investments amounting to $212,493. These temporary investments are of a short maturity with financial institutions with established credit ratings.

The Corporation earns its revenues from a broad base of customers located principally in Pembroke, Beachburg, Killaloe and Mississippi Mills. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

It is management's opinion that the facility is not exposed to significant interest, currency or credit risks arising from its financial instruments.

14. Energy purchase:

The Corporation is dependent on Hydro One for a significant portion of the electricity it purchases. The amount owing to Hydro One at December 31, 2009 is $2,569,084, (2008 - $2,994,675). Included in cost of power in the statement of earnings is $8,218,305 (2008 - $8,102,720) purchased from Hydro One.

15. Other operating revenue:

	2009	2008
Late payment charges	$ 45,304	$ 27,322
Property and equipment rent	44,902	41,817
Change of occupancy and connection fees	45,933	42,945
Labour on customer premises	164,063	123,165
Interest	140,484	263,737
Interest - Ottawa River Energy Solutions Inc.	27,428	12,083
Gain on disposal of capital assets	-	13,375
	$ 468,114	$ 524,444

16. Bank indebtedness, bankers' acceptances and letters of credit:

The Corporation has a bilateral demand line of credit for $1,000,000 with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate. At December 31, 2009, no amounts had been drawn on the line of credit (2008 - $nil).

17. Comparative figures:

Certain of the 2008 comparative figures have been reclassified to conform with the financial presentation adopted in 2009.

HISTORICAL FINANCIAL RESULT FILINGS

Attachment 1 presents the Board-approved balances from ORPC's 2006 EDR application.[1] The attachment also presents the historical financial results by account, as previously filed under the Board's annual reporting requirements,[2] with the following exceptions:

Table 1: Differences between Historical Results and Previous Filings for Variance and Deferral Accounts

	2007		
	As previously filed	Adjustments	Revised Balances
1580-RSVA/WMS	(1,129,988)	5,135	(1,124,853)
1586-RSVA/CN	(776,367)	15,880	(760,487)
1588-RSVA/Power	(263,646)	(20,043)	(283,688)
1590-Recovery of Regulatory Asset Balances	(115,530)	(973)	(116,504)

Certain deferral and variance account balances were restated to adjust for carrying charges recorded in account *1590-Recovery of Regulatory Asset Balances*, rather than the deferral or variance account that gave rise to the carrying charge. These adjustments enhance the consistency of the continuity schedules that appear in Exhibit 9, Tab 1, Schedule 2, Attachment 1.

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[1] EB-2005-0413

[2] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Version dated May 1, 2010, section 2.1.7

Table 2: Differences between Historical Results and Previous Filings for Depreciation Amounts

	2008	2007	2006
As previously filed:			
1925-Computer Software	198,260	23,527	38,464
1995-Contributions and Grants - Credit	(963,537)	(813,516)	(802,025)
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(14,958,385)	(14,342,465)	(13,554,883)
5315-Customer Billing	412,047	240,919	235,569
5705-Amortization Expense - Property, Plant, and Equipment	677,665	693,490	696,722
Adjustments to trial balance:			
1925-Computer Software	251,768	137,241	106,093
1995-Contributions and Grants - Credit	(195,719)	(151,637)	(113,030)
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(56,049)	14,395	6,937
5315-Customer Billing	(114,526)	(31,148)	(33,048)
5705-Amortization Expense - Property, Plant, and Equipment	114,526	31,148	33,048
Revised balances:			
1925-Computer Software	450,027	160,768	144,557
1995-Contributions and Grants - Credit	(1,159,255)	(965,152)	(915,056)
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(15,014,434)	(14,328,070)	(13,547,946)
5315-Customer Billing	297,520	209,771	202,521
5705-Amortization Expense - Property, Plant, and Equipment	792,191	724,638	729,770

In previous annual filings, depreciation on software and capital contributions was netted against the balance in the asset account (accounts #1925 and #1995, respectively), rather than recorded to account #2105 as accumulated amortization. The expense for billing software depreciation was recorded to account #5315, rather than to account #5705 as amortization expense.

These historical balance adjustments enhance the consistency in this rate application between historical results and the information provided for the Bridge and Test years.

Table 3: Differences between Historical Results and Previous Filings for Capital Asset Classifications

	2006		
	As previously filed	Adjustments	Revised Balances
1808-Buildings and Fixtures	502,293	(129,579)	372,714
1820-Distribution Station Equipment	1,924,415	129,579	2,053,994

An asset classification error was corrected in 2007. The related 2006 ending balances have been restated, for consistency with the balances used elsewhere in this application to calculate depreciation expense for rate-setting purposes.[3]

Further adjustments to reflect the half-year rule for depreciation are described in Exhibit 2, Tab 2, Schedule 3. Those adjustments are not reflected in the historical results attached to this schedule.

[3] see Exhibit 4, Tab 7, Schedule 1, Attachment 1

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
1050-Current Assets	1005-Cash	7,618,094.69	7,698,955.25	6,682,614.37	
	1010-Cash Advances and Working Funds	1,688.90	1,688.90	1,688.90	
	1100-Customer Accounts Receivable	866,436.13	1,115,459.01	901,255.78	
	1104-Accounts Receivable - Recoverable Work	183,582.91	112,634.41	114,042.80	
	1110-Other Accounts Receivable	-110,717.64	33,940.23	6,971.77	
	1120-Accrued Utility Revenues	2,685,540.59	2,587,439.30	2,444,204.26	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-70,000.00	-70,000.00	-70,000.00	
	1180-Prepayments	78,299.82	106,005.10	100,316.16	
	1200-Accounts Receivable from Associated Companies	692,310.40	292,486.66	431,375.57	
1100-Inventory	1330-Plant Materials and Operating Supplies	881,637.20	892,356.68	804,895.19	
1150-Non-Current Assets	1460-Other Non-Current Assets	11,274.05			
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	126,447.26	122,171.73	186,114.90	
	1525-Miscellaneous Deferred Debits			18,682.80	
	1545-Development Charge Deposits/ Receivables	-32,492.86		-27,000.00	
	1550-LV Variance Account	266,917.12	168,507.81	69,366.53	
	1555-Smart Meters Capital Variance Account	102,675.24	53,497.82	-15,680.48	
	1556-Smart Meters OM&A Variance Account	58,250.36	6,206.17	643.20	
	1562-Deferred Payments in Lieu of Taxes	-150,498.08	-145,554.59	-139,682.89	
	1565-Conservation and Demand Management Expenditures and Recoveries		-116,197.23	-239,212.42	
	1566-CDM Contra Account		116,197.23	239,212.42	
	1570-Qualifying Transition Costs			375,895.42	
	1571-Pre-market Opening Energy Variance			60,066.10	
	1580-RSVAWMS	-1,614,146.30	-1,124,852.59	-674,730.76	
	1582-RSVAONE-TIME			24,344.77	
	1584-RSVANW	-280,277.77	-246,904.26	-689,824.47	
	1586-RSVACN	-1,156,543.60	-760,486.94	-380,917.35	
	1588-RSVAPOWER	-318,876.87	-283,688.48	-890,271.84	
	1590-Recovery of Regulatory Asset Balances	-125,998.48	-116,503.86	-162,907.85	

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
1450-Distribution Plant	1805-Land	130,499.26	130,499.26	130,499.26	130,499.00
	1806-Land Rights	10,808.84	10,808.84	10,808.84	8,703.00
	1808-Buildings and Fixtures	397,506.28	372,713.64	372,713.64	486,068.00
	1810-Leasehold Improvements	49,714.25	48,402.82	28,814.82	9,540.00
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,084,456.18	2,072,168.43	2,053,993.81	1,892,012.00
	1830-Poles, Towers and Fixtures	8,029,667.87	7,940,798.29	7,823,152.63	7,443,478.00
	1835-Overhead Conductors and Devices	2,217,698.67	2,014,782.80	1,767,113.97	1,060,716.00
	1840-Underground Conduit	2,933,508.47	2,933,508.47	2,933,508.47	2,854,963.00
	1845-Underground Conductors and Devices	252,655.67	247,842.03	204,849.14	95,234.00
	1850-Line Transformers	3,080,605.21	3,020,927.91	2,843,663.32	2,583,980.00
	1855-Services	748,087.57	627,933.70	513,721.37	262,003.00
	1860-Meters	873,921.11	862,511.88	862,584.85	826,266.00
1500-General Plant	1908-Buildings and Fixtures				**-193,826.50**
	1915-Office Furniture and Equipment	122,774.43	122,774.43	122,774.43	127,988.00
	1920-Computer Equipment - Hardware	312,586.79	251,086.43	245,589.05	219,999.00
	1925-Computer Software	450,027.43	160,768.38	144,557.18	18,638.00
	1930-Transportation Equipment	1,579,695.07	1,586,492.76	1,504,987.06	1,371,407.00
	1935-Stores Equipment	1,761.26	1,761.26	1,761.26	1,761.00
	1940-Tools, Shop and Garage Equipment	234,228.66	234,228.66	231,954.73	204,216.00
	1955-Communication Equipment	29,543.89	29,543.89	29,543.89	26,661.00
	1960-Miscellaneous Equipment				4,500.00
	1970-Load Management Controls - Customer Premises	254,912.00	254,912.00	254,912.00	250,715.00
	1975-Load Management Controls - Utility Premises	64,873.19	64,873.19	64,873.19	64,873.00
	1980-System Supervisory Equipment	498,536.09	498,536.09	498,536.09	485,610.00
1550-Other Capital	1995-Contributions and Grants - Credit	-1,159,255.26	-965,152.24	-915,055.80	-367,732.00
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-15,014,434.00	-14,328,069.88	-13,547,945.73	-11,454,867.81
	2120-Accumulated Amortization of Electric Utility Plant - Intangibles	-6,386.00	-6,051.00	-5,716.00	-4,879.00
1650-Current Liabilities	2205-Accounts Payable	-3,273,808.48	-3,750,262.05	-2,350,550.28	
	2208-Customer Credit Balances	-327,569.32	-403,323.69	-207,750.07	

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	2220-Miscellaneous Current and Accrued Liabilities	-202,268.93	-274,405.37	-539,113.65	
	2250-Debt Retirement Charges(DRC) Payable	-72,861.83	-76,391.31	-76,433.53	
	2264-Pensions and Employee Benefits - Current Portion	-3,756.88	-3,563.04	-3,688.64	
	2268-Accrued Interest on Long Term Debt	-101,243.33	-101,243.33	-101,243.33	
	2290-Commodity Taxes	68,962.83	94,925.35	52,321.09	
	2292-Payroll Deductions / Expenses Payable	-20,405.58	-18,813.71	-19,343.86	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	6,112.00	75,124.00	-36,151.00	
1700-Non-Current Liabilities	2310-Vested Sick Leave Liability	-404,167.52	-473,131.07	-263,497.25	
	2335-Long Term Customer Deposits	-268,494.21	-230,687.55	-250,319.47	
1800-Long-Term Debt	2520-Other Long Term Debt	-5,585,838.00	-5,585,838.00	-5,585,838.00	
1850-Shareholders' Equity	3005-Common Shares Issued	-5,585,838.00	-5,585,838.00	-5,585,838.00	
	3045-Unappropriated Retained Earnings	-1,797,392.62	-1,990,452.36	-1,797,868.42	288,946.00
	3046-Balance Transferred From Income	-323,026.13	-308,060.26	-582,343.94	
3000-Sales of Electricity	4006-Residential Energy Sales	-4,173,893.81	-4,359,826.63	-8,863,229.49	-3,898,464.00
	4025-Street Lighting Energy Sales	-131,762.87	-148,976.80	-159,420.62	-134,931.00
	4030-Sentinel Lighting Energy Sales	-12,420.01	-12,592.09	-14,630.93	-12,760.00
	4035-General Energy Sales	-5,647,939.67	-5,997,000.92	-1,846,968.27	-5,850,596.00
	4055-Energy Sales for Resale	-1,378,631.74	-1,117,943.62	-678,494.43	-163,838.00
	4062-Billed WMS	-1,282,851.43	-1,291,765.32	-1,273,298.50	-1,268,992.00
	4066-Billed NW	-865,501.57	-984,533.45	-1,059,199.76	-1,140,056.00
	4068-Billed CN	-1,010,703.43	-1,042,324.44	-1,006,176.14	-984,548.00
	4075-Billed-LV	-231,571.91	**-202,054.31**	-167,107.94	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-3,492,727.08	-3,460,208.82	-3,672,036.41	-3,636,868.00
	4082-Retail Services Revenues	-14,072.50	-11,223.00	-9,077.80	-1,890.00
	4084-Service Transaction Requests (STR) Revenues	-456.50	-549.75	-1,078.75	-11.00
	4090-Electric Services Incidental to Energy Sales				-30,317.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
3100-Other Operating Revenues	4210-Rent from Electric Property	-40,534.45	-39,880.70	-49,229.61	
	4225-Late Payment Charges	-27,321.95	-30,603.19	-25,609.66	-23,883.00
	4230-Sales of Water and Water Power				-18,892.00
	4235-Miscellaneous Service Revenues	-43,850.85	-49,140.00	-39,135.00	-34,410.00
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-83,826.81	-47,033.90	-45,180.43	-54,009.00
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.				11,681.00
	4355-Gain on Disposition of Utility and Other Property	-13,375.34			
	4390-Miscellaneous Non-Operating Income	-9,276.78	-6,019.08	-9,681.28	-1,844.00
3200-Investment Income	4405-Interest and Dividend Income	-148,561.08	-174,669.85	-125,666.38	-101,282.00
3350-Power Supply Expenses	4705-Power Purchased	11,344,648.10	11,636,340.06	11,557,670.14	10,101,698.00
	4710-Cost of Power Adjustments				30,080.00
	4714-Charges-NW	865,501.57	984,533.45	1,059,199.76	1,140,056.00
	4716-Charges-CN	1,010,703.43	1,042,324.44	1,006,176.14	984,548.00
	4730-Rural Rate Assistance Expense	1,282,851.43	1,291,765.32	1,273,298.50	1,268,992.00
	4750-Charges-LV	231,571.91	**202,054.31**	167,107.94	
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	55,361.36	46,584.39	56,726.98	58,407.00
	5010-Load Dispatching	47,561.67	42,245.35	39,592.08	32,872.00
	5012-Station Buildings and Fixtures Expense	133,683.15	139,024.55	131,575.54	133,535.00
	5016-Distribution Station Equipment - Operation Labour	946.91		335.39	801.00
	5017-Distribution Station Equipment - Operation Supplies and Expenses	1,967.47			
	5020-Overhead Distribution Lines and Feeders - Operation Labour				801.00
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,506.85	1,971.92		
	5030-Overhead Subtransmission Feeders - Operation	46.06		1,408.96	801.00
	5035-Overhead Distribution Transformers- Operation	398.90	928.27		
	5040-Underground Distribution Lines and Feeders - Operation Labour				1,601.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	14.82	642.31		
	5055-Underground Distribution Transformers - Operation	69.10	151.28		
	5065-Meter Expense	50,897.56	41,048.44	53,613.44	80,078.00
	5070-Customer Premises - Operation Labour	6,993.03	7,163.32	8,915.10	10,511.00
	5075-Customer Premises - Materials and Expenses	7,015.87	6,079.72	5,957.56	2,203.00
	5085-Miscellaneous Distribution Expense	33,480.16	27,978.73	20,855.31	46,803.00
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,322.94	6,483.83	6,300.44	5,050.00
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	23,044.06		22,604.94	25,267.00
	5114-Maintenance of Distribution Station Equipment	72,432.77	156,243.09	77,505.12	83,442.00
	5120-Maintenance of Poles, Towers and Fixtures	12,069.03	24,915.60	40,522.41	32,104.00
	5125-Maintenance of Overhead Conductors and Devices	184,537.23	93,027.30	116,434.99	40,665.00
	5130-Maintenance of Overhead Services	33,113.12	31,183.76	9,587.73	7,164.00
	5135-Overhead Distribution Lines and Feeders - Right of Way	151,967.43	149,907.14	119,492.48	59,427.00
	5145-Maintenance of Underground Conduit		103.34	2,926.50	3,882.00
	5150-Maintenance of Underground Conductors and Devices	27,868.74	4,893.69	26,152.60	2,961.00
	5155-Maintenance of Underground Services	19,816.31	2,081.96	5,919.39	5,959.00
	5160-Maintenance of Line Transformers	27,973.14	32,268.78	15,534.33	32,570.00
	5175-Maintenance of Meters		742.05		35.00
3650-Billing and Collecting	5310-Meter Reading Expense	107,278.46	104,754.46	107,617.06	100,698.00
	5315-Customer Billing	297,520.24	209,770.97	202,521.49	216,538.00
	5320-Collecting	138,312.90	144,094.34	138,799.96	119,041.00
	5330-Collection Charges	-15,083.00	-16,433.00	-11,717.00	-8,009.00
	5335-Bad Debt Expense	53,092.10	43,520.88	26,603.26	28,835.00
	5340-Miscellaneous Customer Accounts Expenses	-2,005.79	-2,393.01	-1,442.44	2,303.00
3700-Community Relations	5410-Community Relations - Sundry	34,536.75	13,306.25	21,507.35	33,197.00
	5415-Energy Conservation	8,775.08	20,506.64	21,061.45	
	5420-Community Safety Program	28,191.16	17,482.07	21,087.64	17,448.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	5515-Advertising Expense				803.00
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	40,258.71	38,267.66	36,503.80	41,037.00
	5610-Management Salaries and Expenses	216,880.05	239,263.77	246,886.74	240,853.00
	5615-General Administrative Salaries and Expenses	176,285.48	185,023.06	181,675.73	185,410.00
	5620-Office Supplies and Expenses	50,161.64	53,407.73	69,786.54	47,050.00
	5630-Outside Services Employed	6,067.50	32,032.50	37,177.00	69,302.00
	5635-Property Insurance	7,909.68	7,268.40	7,453.37	9,821.00
	5645-Employee Pensions and Benefits	70,278.01	254,428.17	16,082.28	9,423.00
	5655-Regulatory Expenses	53,747.62	38,134.22	36,983.02	47,825.00
	5665-Miscellaneous General Expenses			223.44	216,619.00
	5670-Rent	11,891.16		11,149.63	13,037.00
	5675-Maintenance of General Plant	70,423.35	80,041.32	64,052.34	64,904.00
	5680-Electrical Safety Authority Fees	7,496.87	4,956.39	7,597.79	9,123.00
	5685-Independent Market Operator Fees and Penalties				15,818.00
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	792,191.24	724,638.07	729,769.92	773,286.00
	5710-Amortization of Limited Term Electric Plant	335.00	335.00	335.00	335.00
3900-Interest Expense	6005-Interest on Long Term Debt	404,973.32	404,973.32	404,973.32	
4000-Income Taxes	6110-Income Taxes	92,372.00	98,220.00	260,775.00	42,600.00
Balance Sheet Total		**0.00**	**0.00**	**0.00**	
Net Income		**-323,026.13**	**-308,060.26**	**-582,343.94**	

Reconciliation between Financial Statements and Results Filed

	2006			
	Actuals	Fin. Stmt.	Variance	
Total Assets	17,347,658	19,655,207	**-2,307,549**	
Difference due to:				
Deferral Accounts		-2,094,496	-2,094,496	Credit balances reflected as Liabilities on Fin. Statement
GST		-52,321	-52,321	Balance recorded as a liability in Actuals
PILS		-36,151	-36,151	Balance recorded as a liability in Actuals
Defered PILS		-123,203	-123,203	Balance recorded as a liability in Actuals
Misc Liability		-1,378	-1,378	
TOTAL DIFFERENCES			**-2,307,549**	
Total Liabilities	9,381,608	11,689,157	**-2,307,549**	
Difference due to:				
Deferral Accounts		-2,094,496	-2,094,496	Credit balances reflected as Liabilities on Fin. Statement
GST		-52,321	-52,321	Balance recorded as a liability in Actuals
PILS		-36,151	-36,151	Balance recorded as a liability in Actuals
Defered PILS		-123,203	-123,203	Balance recorded as a liability in Actuals
Misc Liability		-1,378	-1,378	
TOTAL DIFFERENCES			**-2,307,549**	
Total Equity	7,966,050	7,966,050	**0**	
Net Income	582,343	582,343	**0**	
Differences:				
Net Revenues	-3,981,769	-4,111,391	129,622	Actuals include interest on regulatory liabilities ($109K) and misc. interest expense ($9K), F/S includes misc billing revenue ($12K)
OM&A Expenses	2,036,619	2,057,606	-20,987	Actuals include misc billing revenue ($12K); F/S includes misc. interest expense ($9K)
Interest Expense	404,973	513,610	-108,637	F/S includes interest on regulatory liabilities
TOTAL DIFFERENCES			**-1**	

Reconciliation between Financial Statements and Results Filed

	2007			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	18,631,960	21,129,615	**-2,497,655**	
Difference due to:				
Deferral Accounts		-2,203,825	-2,203,825	Credit balances reflected as Liabilities on Fin. Statement
GST		-94,925	-94,925	Balance recorded as a liability in Actuals
PILS		-75,124	-75,124	Balance recorded as a liability in Actuals
Defered PILS		-123,203	-123,203	Balance recorded as a liability in Actuals
Misc Liability		-578	-578	Balance recorded as a liability in Actuals
TOTAL DIFFERENCES			**-2,497,655**	
Total Liabilities		13,245,262	**-13,245,262**	
Difference due to:				
Deferral Accounts		-2,203,825	-2,203,825	Balances recorded as Assets in Actuals
GST		-94,925	-94,925	Balances recorded as Assets in Actuals
PILS		-75,124	-75,124	Balances recorded as Assets in Actuals
Defered PILS		-123,203	-123,203	Balances recorded as Assets in Actuals
Misc Liability		-578	-578	Balances recorded as Assets in Actuals
TOTAL DIFFERENCES			**-2,497,655**	
Total Equity	18,631,960	7,884,353	**0**	
Net Income	308,060	308,060	**0**	
Differences:				
Net Revenues	-3,819,328	-3,942,629	123,301	Actuals include interest on regulatory liabilities ($101K) and misc. interest expense ($6K), F/S includes misc billing revenue ($16K)
OM&A Expenses	2,314,250	2,336,432	-22,182	Actuals include misc billing revenue ($16K); F/S includes misc interest expense ($6K)
Interest Expense	404,973	506,094	-101,121	F/S includes interest on regulatory liabilities
TOTAL DIFFERENCES			**-2**	

Reconciliation between Financial Statements and Results Filed

	2008			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	17,891,596	21,209,789	**-3,318,193**	
Difference due to:				
Deferral Accounts		-2,968,456	-2,968,456	Credit balances reflected as Liabilities on Fin. Statement
GST		-68,963	-68,963	Balance recorded as a liability in Actuals
PILS		-6,112	-6,112	Balance recorded as a liability in Actuals
Inventory Clearing		-4,013	-4,013	Balance recorded as a liability in Actuals
Other Accounts Rec		-114,265	-114,265	Balance recorded as a liability in Actuals
Defered PILS		-123,203	-123,203	Balance recorded as a liability in Actuals
Customer Develop Deposit		-33,181	-33,181	Balance recorded as a liability in Actuals
TOTAL DIFFERENCES			**-3,318,193**	
Total Liabilities	10,185,339	13,503,529	**-3,318,190**	
Difference due to:				
Deferral Accounts		-2,968,456	-2,968,456	Balances recorded as Assets in Actuals
GST		-68,963	-68,963	Balances recorded as Assets in Actuals
PILS		-6,112	-6,112	Balances recorded as Assets in Actuals
Inventory Clearing		-4,013	-4,013	Balances recorded as Assets in Actuals
Other Accounts Rec		-114,265	-114,265	Balance recorded as a liability in Actuals
Defered PILS		-123,203	-123,203	Balance recorded as a liability in Actuals
Customer Develop Deposit		-33,181	-33,181	Balance recorded as a liability in Actuals
TOTAL DIFFERENCES			**-3,318,193**	
Total Equity	7,706,257	7,706,260	**0**	

Reconciliation between Financial Statements and Results Filed

	2008			
	Actuals	Fin. Stmt.	Variance	
Net Income	323,027	323,027	**0**	
Differences:				
Net Revenues	-3,874,003	-4,016,346	142,343	Actuals include interest on regulatory liabilities ($111K) and misc interest expense ($16K); F/S includes misc billing revenue ($15K)
OM&A Expenses	2,375,632	2,378,259	-2,627	Actuals include software amortization ($29K) and misc billing revenue (-$15K); F/S includes misc interest expense (-$16K)
Amortization Expense	678,000	706,600	-28,600	F/S includes software amortization
Interest Expense	404,973	516,114	-111,141	F/S includes interest on regulatory liabilities
Taxes	92,372	92,346	26	Actuals include interest on taxes
TOTAL DIFFERENCES			**1**	

Reconciliation between Financial Statements and Results Filed

	2009			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	16,364,093	21,912,078	**-5,547,985**	
Difference due to:				
Deferral Accounts		-4,583,331	-4,583,331	Credit balances reflected as Liabilities on Fin. Statement
Future income taxes		-861,382	-861,382	Balance recorded as a liability in Actuals
GST		-53,926	-53,926	Balance recorded as a liability in Actuals
PILS		-5,708	-5,708	Balance recorded as a liability in Actuals
Other Accts Receivable		-43,638	-43,638	Balance recorded as a liability in Actuals
TOTAL DIFFERENCES			**-5,547,985**	
Total Liabilities	-8,777,008	-14,324,993	**5,547,985**	
Difference due to:				
Deferral Accounts		4,583,331	4,583,331	Balances recorded as Assets in Actuals
Future income taxes		861,382	861,382	Balances recorded as Assets in Actuals
GST		53,926	53,926	Balances recorded as Assets in Actuals
PILS		5,708	5,708	Stated on Fin. Stmt. as net Due to Assoc. Co. in Liabilities
Other Accts Receivable		43,638	43,638	
TOTAL DIFFERENCES			**5,547,985**	
Total Equity	25,141,101	36,237,071	**0**	
Net Income	354,109	354,109	**0**	
Differences:				
Net Revenues	-3,995,714	-4,011,993	16,279	Actuals include interest on customer deposits ($2K); F/S includes misc billing revenue ($16K)
OM&A Expenses	2,419,382	2,416,283	3,099	Actuals include software amortization ($21K), misc billing revenue (-$16K) and interest on customer deposits (-$2K)
Amortization Expense	675,335	696,514	-21,179	F/S includes software amortization
Interest Expense	473,972	472,171	1,801	F/S includes interest on customer deposits
TOTAL DIFFERENCES			**0**	

FINANCIAL PROJECTIONS

Attachment 1 describes the budgeting process used by Ottawa River Power Corporation to prepare its projections for the 2010 test year. Attachment 2 describes certain changes in budgeting methodology which were adopted in preparing projections for the 2010 test year. Attachment 3 shows the pro-forma Income Statement and Balance Sheet for the 2010 test year.

Budget Directives and Assumptions

ORPC compiles budget information for three major components of the budgeting process: revenue forecasts, operation, maintenance and administration forecasts and capital forecast. Budget information was prepared for both the Bridge and Test Years. Bridge forecasts were updated based on actual 2009 results, and the 2010 Test Year projections were also reviewed in light of 2009 results.

REVENUE FORECAST

The revenue budget includes three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2010 was forecast using the weather normalized load forecast prepared by Elenchus Research Associates ("ERA") as presented in Exhibit 3, Tab 1, Schedule 2, Attachment 1. Rates for energy pass-through charges are described in Exhibit 3, Tab 1, Schedule 3.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project revenue for the 2010 test year. Other revenues were reviewed on an item by item basis with each account projection being determined based on the most reliable historical indicator.

OPERATIONS, MAINTENANCE AND EXPENSE FORECAST

The OM&A expense for the Bridge and Test Years were forecast using work plans, negotiated wage settlement, capital budgets and prior years historical costs. The expenditures were submitted to the Board of Directors for approval.

CAPITAL BUDGET

The capital budget is formulated on a project by project basis. ORPC completes inspections throughout the year while performing maintenance on the distribution system and other infrastructure. From these inspections capital projects are identified and prioritized for the upcoming year's budget.

Capital spending is attributed primarily to the replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to ORPC's customers.

Additional information on ORPC's approach to investment planning is included in Exhibit 2, Tab 4, Schedule 4.

Changes in Methodology

The pro-forma projections for the 2010 test year were prepared in accordance with ORPC's usual process, including the directions and assumptions described in the preceding attachment, with the following exceptions:

1. Rates for Distribution and Sales of Electricity are assumed to be constant for the entire calendar year.
2. Depreciation expense reflects the half-year rule for capital additions.
3. No amount for Provincial Sales Tax ("PST") was included in the 2010 spending projections for capital expenditure or for OM&A expenses. Instead, ORPC seeks to defer PST amounts actually paid in the first six months of 2010 for future recovery, as explained in Exhibit 9, Tab 1, Schedule 1. For OM&A, the total estimated savings from eliminating PST for the full year is reflected in the 2010 projection for account '6105-Taxes Other Than Income Taxes'. For capital spending, estimated savings of $43,754 are reflected in the individual asset account balances and project costs.
4. Regulatory costs and incremental one-time cost for the transition to International Financial Reporting Standards have been normalized, as well as the addition of four apprentices to replace an aging workforce, by reflecting in 2010 one quarter of the total projected costs for years 2010 to 2013.

2010 Pro-Forma Financial Statements

Account Grouping	2010 @ existing rates	2010 @ new dist. rates
3000-Sales of Electricity	16,175,760	16,175,760
3050-Revenues From Services - Distribution	3,597,384	4,015,185
3100-Other Operating Revenues	134,325	134,325
3150-Other Income & Deductions	97,000	97,000
3200-Investment Income	88,820	110,000
3350-Power Supply Expenses	-16,175,760	-16,175,760
Net Revenues	3,917,529	4,356,510
3500-Distribution Expenses - Operation	360,476	360,476
3550-Distribution Expenses - Maintenance	705,409	705,409
3650-Billing and Collecting	616,443	616,443
3700-Community Relations	58,624	58,624
3800-Administrative and General Expenses	859,815	859,815
3950-Taxes Other Than Income Taxes	-29,915	-29,915
OM&A Expenses	2,570,853	2,570,853
3850-Amortization Expense	791,805	791,805
Earnings Before Interest & Taxes	554,871	993,852
3900-Interest Expense	404,973	404,973
Earnings Before Tax	149,898	588,879
4000-Income Taxes		56,851
Net Income excluding Extraordinary Items	149,898	532,027
4100-Extraordinary & Other Items		
Net Income	**149,898**	**532,027**

2010 Pro-Forma Financial Statements

Account Grouping	2010 @ existing rates	2010 @ new dist. rates
1050-Current Assets	11,177,863	10,776,030
1100-Inventory	850,000	850,000
1150-Non-Current Assets	120,000	120,000
1200-Other Assets and Deferred Charges	-4,580,813	-3,796,850
1300-Intangible Plant		
1450-Distribution Plant	22,754,740	22,754,740
1500-General Plant	3,838,079	3,838,079
1550-Other Capital Assets	-1,381,491	-1,381,491
1600-Accumulated Amortization	-16,352,597	-16,352,597
Total Assets	**16,425,781**	**16,807,911**
1650-Current Liabilities	2,613,350	2,613,350
1700-Non-Current Liabilities	500,000	500,000
1800-Long-Term Debt	5,585,838	5,585,838
Total Liabilities	8,699,188	8,699,188
1850-Shareholders' Equity	7,726,593	8,108,723
Total Liabilities & Shareholders' Equity	**16,425,781**	**16,807,911**

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

ORPC has not issued any shares since its cost of service application for 2006 rates.

The utility's outstanding debt is disclosed in Exhibit 5, Tab 1, Schedule 2, Attachment 1. ORPC has no plan to assume any other debt at this time.

ORPC does not have a prospectus, nor does it plan to prepare one.

MATERIALITY THRESHOLD

OPRC's annual revenue requirement is well below $10 million. In accordance with section 2.2.4 of the Board's filing requirements, a materiality threshold of $50,000 applies throughout this application.

Revenue Sufficiency / Deficiency

Note: More details on ORPC's Revenue Deficiency are presented in Exhibit 6

		2010 Projection
Utility Income	*(see below)*	570,051
Utility Rate Base		11,518,294
Indicated Rate of Return		4.95%
Requested / Approved Rate of Return		8.08%
Sufficiency / (Deficiency) in Return		(3.13%)
Net Revenue Sufficiency / (Deficiency)		**-360,950**
Provision for PILs/Taxes		-56,851
Gross Revenue Sufficiency / (Deficiency)		**-417,801**
Deemed Overall Debt Rate		*6.90%*
Deemed Cost of Debt		*477,180*
Utility Income less Deemed Cost of Debt		*92,871*
Return On Deemed Equity		*2.02%*

UTILITY INCOME

Total Net Revenues	3,932,709
OM&A Expenses	2,600,768
Depreciation & Amortization	791,805
Taxes other than PILs / Income Taxes	-29,915
Total Costs & Expenses	3,362,658
Utility Income before Income Taxes / PILs	570,051
PILs / Income Taxes	
Utility Income	**570,051**

REVENUE REQUIREMENT WORK FORM

Attached is the Board's Revenue Requirement Work Form for this Application.

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Ottawa River Power Corporation	(1)
File Number:	EB-2009-0165	
Rate Year:	2010	***Version:*** ***1.0***

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Ontario

		Data Input					(1)
		Application		**Adjustments**		**Per Board Decision**	
1	**Rate Base**						
	Gross Fixed Assets (average)	$24,712,092	**(4)**			$24,712,092	
	Accumulated Depreciation (average)	($16,005,790)	**(5)**			($16,005,790)	
	Allowance for Working Capital:						
	Controllable Expenses	$2,570,853	(6)			$2,570,853	
	Cost of Power	$16,175,760				$16,175,760	
	Working Capital Rate (%)	15.00%				15.00%	
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$3,554,741					
	Distribution Revenue at Proposed Rates	$3,972,542					
	Other Revenue:						
	Specific Service Charges	$47,325					
	Late Payment Charges	$45,000					
	Other Distribution Revenue	$84,643					
	Other Income and Deductions	$201,000					
	Operating Expenses:						
	OM+A Expenses	$2,600,768				$2,600,768	
	Depreciation/Amortization	$791,805				$791,805	
	Property taxes	($29,915)				($29,915)	
	Capital taxes	$0					
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($155,352)	**(3)**				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$47,755					
	Income taxes (grossed up)	$56,851					
	Capital Taxes	$ -					
	Federal tax (%)	11.00%					
	Provincial tax (%)	5.00%					
	Income Tax Credits	$ -					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	**(2)**				**(2)**
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)	0.0%					
						Capital Structure must total 100%	
	Cost of Capital						
	Long-term debt Cost Rate (%)	7.25%					
	Short-term debt Cost Rate (%)	2.07%					
	Common Equity Cost Rate (%)	9.85%					
	Prefered Shares Cost Rate (%)	0.00%					

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$24,712,092	$ -	$24,712,092
2	Accumulated Depreciation (average)	(3)	($16,005,790)	$ -	($16,005,790)
3	Net Fixed Assets (average)	(3)	$8,706,302	$ -	$8,706,302
4	Allowance for Working Capital	(1)	$2,811,992	$ -	$2,811,992
5	**Total Rate Base**		$11,518,294	$ -	$11,518,294

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Application	Adjustments	Per Board Decision
6	Controllable Expenses		$2,570,853	$ -	$2,570,853
7	Cost of Power		$16,175,760	$ -	$16,175,760
8	Working Capital Base		$18,746,614	$ -	$18,746,614
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$2,811,992	$ -	$2,811,992

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.

(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$3,972,542	$ -	$3,972,542
2	Other Revenue	(1)	$377,968	$ -	$377,968
3	Total Operating Revenues		$4,350,510	$ -	$4,350,510
	Operating Expenses:				
4	OM+A Expenses		$2,600,768	$ -	$2,600,768
5	Depreciation/Amortization		$791,805	$ -	$791,805
6	Property taxes		($29,915)	$ -	($29,915)
7	Capital taxes		$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -
9	Subtotal		$3,362,658	$ -	$3,362,658
10	Deemed Interest Expense		$477,180	$ -	$477,180
11	Total Expenses (lines 4 to 10)		$3,839,838	$ -	$3,839,838
12	**Utility income before income taxes**		$510,672	$ -	$510,672
13	Income taxes (grossed-up)		$56,851	$ -	$56,851
14	**Utility net income**		$453,821	$ -	$453,821

Notes

		Application	Per Board Decision
(1)	**Other Revenues / Revenue Offsets**		
	Specific Service Charges	$47,325	$47,325
	Late Payment Charges	$45,000	$45,000
	Other Distribution Revenue	$84,643	$84,643
	Other Income and Deductions	$201,000	$201,000
	Total Revenue Offsets	$377,968	$377,968

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$453,821	$453,821
2	Adjustments required to arrive at taxable utility income	($155,352)	($155,352)
3	Taxable income	$298,469	$298,469
	Calculation of Utility income Taxes		
4	Income taxes	$47,755	$47,755
5	Capital taxes	$ -	$ -
6	Total taxes	$47,755	$47,755
7	Gross-up of Income Taxes	$9,096	$9,096
8	Grossed-up Income Taxes	$56,851	$56,851
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$56,851	$56,851
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	11.00%	11.00%
12	Provincial tax (%)	5.00%	5.00%
13	Total tax rate (%)	16.00%	16.00%

Notes

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$6,450,245	7.25%	$467,643
2	Short-term Debt	4.00%	$460,732	2.07%	$9,537
3	**Total Debt**	60.00%	$6,910,976	6.90%	$477,180
	Equity				
4	Common Equity	40.00%	$4,607,318	9.85%	$453,821
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$4,607,318	9.85%	$453,821
7	**Total**	100%	$11,518,294	8.08%	$931,001
	Per Board Decision				
		(%)	($)	(%)	
	Debt				
8	Long-term Debt	56.00%	$6,450,245	7.25%	$467,643
9	Short-term Debt	4.00%	$460,732	2.07%	$9,537
10	**Total Debt**	60.00%	$6,910,976	6.90%	$477,180
	Equity				
11	Common Equity	40.0%	$4,607,318	9.85%	$453,821
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$4,607,318	9.85%	$453,821
14	**Total**	100%	$11,518,294	8.08%	$931,001

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$417,801		$417,801
2	Distribution Revenue	$3,554,741	$3,554,741	$3,554,741	$3,554,741
3	Other Operating Revenue Offsets - net	$377,968	$377,968	$377,968	$377,968
4	**Total Revenue**	$3,932,709	$4,350,510	$3,932,709	$4,350,510
5	Operating Expenses	$3,362,658	$3,362,658	$3,362,658	$3,362,658
6	Deemed Interest Expense	$477,180	$477,180	$477,180	$477,180
	Total Cost and Expenses	$3,839,838	$3,839,838	$3,839,838	$3,839,838
7	**Utility Income Before Income Taxes**	$92,871	$510,672	$92,871	$510,672
8	Tax Adjustments to Accounting Income per 2009 PILs	($155,352)	($155,352)	($155,352)	($155,352)
9	**Taxable Income**	($62,481)	$355,320	($62,481)	$355,320
10	Income Tax Rate	16.00%	16.00%	16.00%	16.00%
11	**Income Tax on Taxable Income**	($9,997)	$56,851	($9,997)	$56,851
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$102,868	$453,821	$102,868	$453,821
14	**Utility Rate Base**	$11,518,294	$11,518,294	$11,518,294	$11,518,294
	Deemed Equity Portion of Rate Base	$4,607,318	$4,607,318	$4,607,318	$4,607,318
15	Income/Equity Rate Base (%)	2.23%	9.85%	2.23%	9.85%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.85%	9.85%
	Sufficiency/Deficiency in Return on Equity	-7.62%	0.00%	-7.62%	0.00%
17	Indicated Rate of Return	5.04%	8.08%	5.04%	8.08%
18	Requested Rate of Return on Rate Base	8.08%	8.08%	8.08%	8.08%
19	Sufficiency/Deficiency in Rate of Return	-3.05%	0.00%	-3.05%	0.00%
20	Target Return on Equity	$453,821	$453,821	$453,821	$453,821
21	Revenue Sufficiency/Deficiency	$350,953	$ -	$350,953	$ -
22	**Gross Revenue Sufficiency/Deficiency**	$417,801 **(1)**		$417,801 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

Line No.	Particulars	Revenue Requirement: Application		Revenue Requirement: Per Board Decision	
1	OM&A Expenses	$2,600,768		$2,600,768	
2	Amortization/Depreciation	$791,805		$791,805	
3	Property Taxes	($29,915)		($29,915)	
4	Capital Taxes	$ -		$ -	
5	Income Taxes (Grossed up)	$56,851		$56,851	
6	Other Expenses	$ -		$ -	
7	Return				
	Deemed Interest Expense	$477,180		$477,180	
	Return on Deemed Equity	$453,821		$453,821	
8	Distribution Revenue Requirement before Revenues	$4,350,510		$4,350,510	
9	Distribution revenue	$3,972,542		$3,972,542	
10	Other revenue	$377,968		$377,968	
11	**Total revenue**	$4,350,510		$4,350,510	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$ -	**(1)**

Notes

(1) Line 11 - Line 8

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: Ottawa River Power Corporation
File Number: EB-2009-0165
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order								
		Monthly Delivery Charge					Total Bill			
			Per Draft	Change				Per Draft	Change	
		Current	Rate Order	$	%		Current	Rate Order	$	%
Residential	**800 kWh/month**	$ 29.91	$ 22.63	-$ 7.28	-24.3%		$ 90.58	$ 79.75	-$ 10.83	-12.0%
GS < 50kW	**2000** kWh/month	$ 58.83	$ 51.85	-$ 6.98	-11.9%		$ 217.24	$ 201.40	-$ 15.84	-7.3%

Notes:

Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

Attachment 1 shows the trend in OPRC's rate base, which has increased from $10.8 million in the 2006 EDR to $11.5 million in this application.

More than 60% of the change arises from a higher Working Capital Allowance, primarily due to the increase in the Cost of Power. The balance of the difference reflects higher investment in net fixed assets, mainly for overhead conductors/devices, services and distribution stations. The variances are explained in greater detail in Schedule 2.

Rate Base Trend Table

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Net Capital Assets in Service:						
Opening Balance		8,869,590	8,255,268	8,298,295	8,380,450	8,553,872
Ending Balance		8,255,268	8,298,295	8,380,450	8,553,872	8,858,732
Average Balance	8,408,527	8,562,429	8,276,782	8,339,373	8,467,161	8,706,302
Working Capital Allowance *(see below)*	2,351,008	2,560,054	2,616,018	2,549,457	2,486,133	2,811,992
Total Rate Base	**10,759,535**	**11,122,483**	**10,892,800**	**10,888,830**	**10,953,294**	**11,518,294**

Expenses for Working Capital

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	368,413	318,980	313,818	339,943	330,998	360,476
3550-Distribution Expenses - Maintenance	298,526	442,981	501,851	559,145	613,327	705,409
3650-Billing and Collecting	459,406	462,382	483,315	579,115	590,073	616,443
3700-Community Relations	51,448	63,656	51,295	71,503	43,859	58,624
3800-Administrative and General Expenses	970,222	715,572	932,823	711,400	738,324	859,815
3950-Taxes Other Than Income Taxes						-29,915
Total Eligible Distribution Expenses	2,148,015	2,003,572	2,283,102	2,261,106	2,316,581	2,570,853
3350-Power Supply Expenses	13,525,374	15,063,452	15,157,018	14,735,276	14,257,639	16,175,760
Total Expenses for Working Capital	15,673,389	17,067,024	17,440,119	16,996,382	16,574,220	18,746,614
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,351,008**	**2,560,054**	**2,616,018**	**2,549,457**	**2,486,133**	**2,811,992**

RATE BASE VARIANCE ANALYSIS

Attachment 1 shows the annual variances in the rate base. Variances in fixed asset balances are described in Exhibit 2 Tab 3 Schedule 1. Variances in the Working Capital Allowance are described in Exhibit 2 Tab 5 Schedule 1.

2010 Test Year vs. 2009 Bridge Year:

The projected rate base in 2010 of $11.5 million is $565K higher than in 2009. $326K of the difference is due to a higher Working Capital Allowance, reflecting increased power supply costs. The balance of the difference arose from higher net fixed assets, primarily due to increased investments in station equipment and transportation equipment.

2009 Bridge Year vs. 2008 Actual:

The rate base in 2009 of $11.0 million was $64K higher than in 2009. An increase of $128K in net fixed assets, mainly due to increase investments in station equipment, was partially offset by a lower Working Capital Allowance, reflecting lower power supply costs.

2008 Actual vs. 2007 Actual

The rate base in 2008 of $10.9 million was essentially unchanged from 2007. A decrease in the Working Capital Allowance, reflecting lower power supply costs, was offset by higher net fixed assets, largely due to increased investments in transportation equipment and overhead conductors/devices.

2007 Actual vs. 2006 Actual

The rate base in 2007 of $10.9 million was $230K lower than in 2006. A decrease of $286K in net fixed assets, largely due to lower investment in poles and higher capital contributions, was partially offset by a higher Working Capital Allowance, reflecting higher expenses for administration and maintenance.

2006 Actual vs. 2006 Board-Approved

The rate base in 2006 of $11.1 million was $363K higher than the 2006 Board Approved amount. $209K of the difference arose from a higher Working Capital Allowance, reflecting higher power supply costs. The balance of the difference was due to higher net fixed assets.

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2010 Projection	2009 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	8,553,872	8,380,450	**173,422**	**2.1%**
Ending Balance	8,858,732	8,553,872	**304,860**	**3.6%**
Average Balance	8,706,302	8,467,161	**239,141**	**2.8%**
Working Capital Allowance *(see below)*	2,811,992	2,486,133	**325,859**	**13.1%**
Total Rate Base	**11,518,294**	**10,953,294**	**565,000**	**5.2%**

Variances in excess of $50,000 are shown in bold

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	360,476	330,998	29,478	8.9%
3550-Distribution Expenses - Maintenance	705,409	613,327	**92,082**	**15.0%**
3650-Billing and Collecting	616,443	590,073	26,370	4.5%
3700-Community Relations	58,624	43,859	14,765	33.7%
3800-Administrative and General Expenses	859,815	738,324	**121,492**	**16.5%**
3950-Taxes Other Than Income Taxes	-29,915		-29,915	
Total Eligible Distribution Expenses	2,570,853	2,316,581	**254,272**	**11.0%**
3350-Power Supply Expenses	16,175,760	14,257,639	**1,918,122**	**13.5%**
Total Expenses for Working Capital	18,746,614	16,574,220	**2,172,394**	**13.1%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,811,992**	**2,486,133**	**325,859**	**13.1%**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2009 Projection	2008 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	8,380,450	8,298,295	**82,154**	**1.0%**
Ending Balance	8,553,872	8,380,450	**173,422**	**2.1%**
Average Balance	8,467,161	8,339,373	**127,788**	**1.5%**
Working Capital Allowance *(see below)*	2,486,133	2,549,457	**-63,324**	**(2.5%)**
Total Rate Base	**10,953,294**	**10,888,830**	**64,464**	**0.6%**

Variances in excess of $50,000 are shown in bold

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	330,998	339,943	-8,945	(2.6%)
3550-Distribution Expenses - Maintenance	613,327	559,145	**54,182**	**9.7%**
3650-Billing and Collecting	590,073	579,115	10,958	1.9%
3700-Community Relations	43,859	71,503	-27,644	(38.7%)
3800-Administrative and General Expenses	738,324	711,400	26,924	3.8%
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	2,316,581	2,261,106	**55,475**	**2.5%**
3350-Power Supply Expenses	14,257,639	14,735,276	**-477,638**	**(3.2%)**
Total Expenses for Working Capital	16,574,220	16,996,382	**-422,162**	**(2.5%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,486,133**	**2,549,457**	**-63,324**	**(2.5%)**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2008 Actual	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	8,298,295	8,255,268	43,028	0.5%
Ending Balance	8,380,450	8,298,295	**82,154**	**1.0%**
Average Balance	8,339,373	8,276,782	**62,591**	**0.8%**
Working Capital Allowance *(see below)*	2,549,457	2,616,018	**-66,561**	**(2.5%)**
Total Rate Base	**10,888,830**	**10,892,800**	**-3,970**	**(0.0%)**

Expenses for Working Capital ***Variances in excess of $50,000 are shown in bold***

	2008 Actual	2007 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	339,943	313,818	26,125	8.3%
3550-Distribution Expenses - Maintenance	559,145	501,851	**57,294**	**11.4%**
3650-Billing and Collecting	579,115	483,315	**95,800**	**19.8%**
3700-Community Relations	71,503	51,295	20,208	39.4%
3800-Administrative and General Expenses	711,400	932,823	**-221,423**	**(23.7%)**
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	2,261,106	2,283,102	-21,996	(1.0%)
3350-Power Supply Expenses	14,735,276	15,157,018	**-421,741**	**(2.8%)**
Total Expenses for Working Capital	16,996,382	17,440,119	**-443,737**	**(2.5%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,549,457**	**2,616,018**	**-66,561**	**(2.5%)**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	8,255,268	8,869,590	**-614,322**	**(6.9%)**
Ending Balance	8,298,295	8,255,268	43,028	0.5%
Average Balance	8,276,782	8,562,429	**-285,647**	**(3.3%)**
Working Capital Allowance *(see below)*	2,616,018	2,560,054	**55,964**	**2.2%**
Total Rate Base	**10,892,800**	**11,122,483**	**-229,683**	**(2.1%)**

Expenses for Working Capital

Variances in excess of $50,000 are shown in bold

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	313,818	318,980	-5,162	(1.6%)
3550-Distribution Expenses - Maintenance	501,851	442,981	**58,870**	**13.3%**
3650-Billing and Collecting	483,315	462,382	20,932	4.5%
3700-Community Relations	51,295	63,656	-12,361	(19.4%)
3800-Administrative and General Expenses	932,823	715,572	**217,252**	**30.4%**
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	2,283,102	2,003,572	**279,530**	**14.0%**
3350-Power Supply Expenses	15,157,018	15,063,452	**93,565**	**0.6%**
Total Expenses for Working Capital	17,440,119	17,067,024	**373,095**	**2.2%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,616,018**	**2,560,054**	**55,964**	**2.2%**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	8,869,590			
Ending Balance	8,255,268			
Average Balance	8,562,429	8,408,527	**153,902**	**1.8%**
Working Capital Allowance *(see below)*	2,560,054	2,351,008	**209,045**	**8.9%**
Total Rate Base	**11,122,483**	**10,759,535**	**362,947**	**3.4%**

Expenses for Working Capital — ***Variances in excess of $50,000 are shown in bold***

	2006 Actual	2006 EDR Approved	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	318,980	368,413	-49,433	(13.4%)
3550-Distribution Expenses - Maintenance	442,981	298,526	**144,455**	**48.4%**
3650-Billing and Collecting	462,382	459,406	2,976	0.6%
3700-Community Relations	63,656	51,448	12,208	23.7%
3800-Administrative and General Expenses	715,572	970,222	**-254,650**	**(26.2%)**
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	2,003,572	2,148,015	**-144,443**	**(6.7%)**
3350-Power Supply Expenses	15,063,452	13,525,374	**1,538,078**	**11.4%**
Total Expenses for Working Capital	17,067,024	15,673,389	**1,393,635**	**8.9%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**2,560,054**	**2,351,008**	**209,045**	**8.9%**

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

Ottawa River Power Corporation applies the following general capitalization policies and principles based on Generally Accepted Accounting Principles ("GAAP"), in particular CICA Handbook Section 3060 Capital Assets, as well as guidelines set out by the Ontario Energy Board, where applicable:

- The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary cost incurred to place a capital asset into its intended state of operation.

- Assets that are expected to provide future economic benefit greater than one year will be capitalized

- Individual items such as the following

    - New plant providing services over the value of $1,000.

    - Rebuilding of facilities or vehicles when the value is over $2,000 and when the life of this equipment or facility will be extended.

    - Equipment over the value of $500.

ASSET RETIREMENT POLICY

Ottawa River Power Corporation does not have a formal asset retirement policy in place.

ORPC generally retires capital assets from its balance sheet when these assets are no longer in service. There is one exception in this rate application, for legacy meters that will be removed from service with the deployment of smart meters. In accordance with Board policy,[1] these assets remain part of the rate base until such time the Board approves a disposition of ORPC's stranded costs for legacy meters.

The only other planned asset retirements are for vehicles reaching the end of their typical useful life. One such retirement is expected in 2010.

ORPC has no Asset Retirement Obligations at this time.

[1] Guideline G-2008-0002: Smart Meter Funding and Cost Recovery, October 22, 2008, Appendix B

DEPRECIATION POLICY

Ottawa River Power Corporation uses the straight line method of amortization which reflects a constant charge to income for the service as a function of time, based on the estimated average useful life of the asset. The estimated average useful lives of various asset categories are consistent with Board policy.[1]

For financial reporting purposes, ORPC records a full year of depreciation expense on new capital assets in the year they are added. For rate-setting purposes, ORPC has applied the half-year rule for depreciation retrospectively since the Board-approved balances for the 2006 EDR. This restatement is reflected in the depreciation expense calculations,[2] as well the net fixed asset balances used in deriving the rate base.[3]

[1] Ontario Energy Board, 2006 Electricity Distribution Rate Handbook, May 11, 2005, Appendix B

[2] Exhibit 4, Tab 7, Schedule 1, Attachment 1

[3] Exhibit 2, Tab 3, Schedule 2

CAPITAL CONTRIBUTION POLICY

Capital contributions are calculated in accordance with the Distribution System Code ("DSC"). The expansion of ORPC's distribution system is regularly completed to accommodate customer-driven requests for service or additional power requirements. An economic evaluation tool is used with each request to determine whether the future incremental distribution revenue from the system expansion will pay for the capital costs and ongoing maintenance costs of this expansion. A shortfall in revenue will result in a capital contribution being required from the customer. Where future customer connections make use of an expansion within five years, an adjustment is made back to the original customer.

Further to the requirements of the DSC, ORPC also provides transformation for new commercial developments. In addition, capital contributions are obtained from road authorities on a shared basis for electrical plant rearrangements required by road work.

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

Attachment 1 shows the annual variances in the balances for gross capital assets. The investments leading to increases in specific account balances are described in Exhibit 2, Tab 4: Schedule 2 describes the capital projects up to year 2008, while Schedule 3 describes the capital projects in 2009 and 2010.

2010 Test Year vs. 2009 Bridge Year:

The total projected ending balance in 2010 of $25.2 million is $1.0 million greater than 2009. The increase is primarily due to material increases in transformers for downtown revitalization ($180K), distribution station equipment ($150K), the replacement of a line truck ($133K) and the replacement of the SCADA system ($80K), transformers ($180K) for downtown revitalization and commercial development, as well as increases in poles, overhead conductors/devices, underground conduit, conductors and devices and services ($185k).

2009 Bridge Year vs. 2008 Actual:

The total ending balance of $24.2 million in 2009 was $1.0 million greater than in 2008. The largest factor was the building of a new substation in Almonte ($480K). The other material increases occurred in overhead conductors/devices, services, line transformers, poles and underground conductors/devices.

2008 Actual vs. 2007 Actual:

The total ending balance in 2008 was $23.2 million was $676K greater than 2007. $289K of the increase was due to the purchase of a new customer information system (“CIS”) after the former platform was discontinued. Other material increases occurred in computer hardware to operate the new CIS, overhead conductors/devices, services, poles and line transformers.

2007 Actual vs. 2006 Actual:

The ending balance in 2007 was $22.5 million, $793K greater than 2006. The material increases included overhead conductors/devices, line transformers, poles, services, and transportation equipment, reflecting the replacement of a boom truck (chassis only in 2007) and the purchase of a service van.

2006 Actual vs. 2006 Board-Approved:

The actual ending balance in 2006 was $21.7 million, $1.9 million greater than the 2006 Board Approved amount which was the average of the 2003 and 2004 ending balances in the historical test year filing. The variance thus represents all investments completed in 2005 and 2006, as well as one half of the investments completed in 2004. $1.8 million of the difference reflects balance increases in overhead conductors/devices, poles, line transformers, services and underground plant. In addition, the 2006 Board Approved amount included a negative adjustment of $194K, which was reflected in an unused account (1908-Buildings and Fixtures) but actually represents a prior period adjustment to accumulated depreciation for understated amortization from 2001 to 2004.

Gross Asset Variances Table

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
1450-Distribution Plant	1805-Land	154,499	130,499	24,000	18.4%
	1806-Land Rights	10,809	10,809		
	1808-Buildings and Fixtures	463,835	403,835	**60,000**	**14.9%**
	1810-Leasehold Improvements	49,714	49,714		
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,713,071	2,563,071	**150,000**	**5.9%**
	1830-Poles, Towers and Fixtures	8,211,190	8,107,720	**103,470**	**1.3%**
	1835-Overhead Conductors and Devices	2,511,335	2,430,845	**80,490**	**3.3%**
	1840-Underground Conduit	2,984,508	2,933,508	**51,000**	**1.7%**
	1845-Underground Conductors and Devices	412,689	330,339	**82,350**	**24.9%**
	1850-Line Transformers	3,379,771	3,200,351	**179,420**	**5.6%**
	1855-Services	962,551	875,351	**87,200**	**10.0%**
	1860-Meters	900,768	876,768	24,000	2.7%
1500-General Plant	1908-Buildings and Fixtures				
	1915-Office Furniture and Equipment	130,774	122,774	8,000	6.5%
	1920-Computer Equipment - Hardware	326,010	320,010	6,000	1.9%
	1925-Computer Software	472,929	454,229	18,700	4.1%
	1930-Transportation Equipment	1,727,079	1,593,935	**133,143**	**8.4%**
	1935-Stores Equipment	1,761	1,761		
	1940-Tools, Shop and Garage Equipment	244,229	234,229	10,000	4.3%
	1955-Communication Equipment	33,244	29,544	3,700	12.5%
	1960-Miscellaneous Equipment				
	1970-Load Management Controls - Customer Premises	254,912	254,912		
	1975-Load Management Controls - Utility Premises	64,873	64,873		
	1980-System Supervisory Equipment	582,268	502,268	**80,000**	**15.9%**
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-1,381,491	-1,278,491	**-103,000**	**(8.1%)**
TOTAL		**25,211,329**	**24,212,855**	**998,473**	**4.1%**

Gross Asset Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	130,499	130,499		
	1806-Land Rights	10,809	10,809		
	1808-Buildings and Fixtures	403,835	397,506	6,329	1.6%
	1810-Leasehold Improvements	49,714	49,714		
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,563,071	2,084,456	**478,615**	**23.0%**
	1830-Poles, Towers and Fixtures	8,107,720	8,029,668	**78,052**	**1.0%**
	1835-Overhead Conductors and Devices	2,430,845	2,217,699	**213,146**	**9.6%**
	1840-Underground Conduit	2,933,508	2,933,508		
	1845-Underground Conductors and Devices	330,339	252,656	**77,683**	**30.7%**
	1850-Line Transformers	3,200,351	3,080,605	**119,746**	**3.9%**
	1855-Services	875,351	748,088	**127,263**	**17.0%**
	1860-Meters	876,768	873,921	2,847	0.3%
1500-General Plant	1908-Buildings and Fixtures				
	1915-Office Furniture and Equipment	122,774	122,774		
	1920-Computer Equipment - Hardware	320,010	312,587	7,423	2.4%
	1925-Computer Software	454,229	450,027	4,202	0.9%
	1930-Transportation Equipment	1,593,935	1,579,695	14,240	0.9%
	1935-Stores Equipment	1,761	1,761		
	1940-Tools, Shop and Garage Equipment	234,229	234,229		
	1955-Communication Equipment	29,544	29,544		
	1960-Miscellaneous Equipment				
	1970-Load Management Controls - Customer Premises	254,912	254,912		
	1975-Load Management Controls - Utility Premises	64,873	64,873		
	1980-System Supervisory Equipment	502,268	498,536	3,732	0.7%
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-1,278,491	-1,159,255	**-119,236**	**(10.3%)**
TOTAL		**24,212,855**	**23,198,813**	**1,014,042**	4.4%

Gross Asset Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	130,499	130,499		
	1806-Land Rights	10,809	10,809		
	1808-Buildings and Fixtures	397,506	372,714	24,793	6.7%
	1810-Leasehold Improvements	49,714	48,403	1,311	2.7%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,084,456	2,072,168	12,288	0.6%
	1830-Poles, Towers and Fixtures	8,029,668	7,940,798	**88,870**	1.1%
	1835-Overhead Conductors and Devices	2,217,699	2,014,783	**202,916**	10.1%
	1840-Underground Conduit	2,933,508	2,933,508		
	1845-Underground Conductors and Devices	252,656	247,842	4,814	1.9%
	1850-Line Transformers	3,080,605	3,020,928	**59,677**	2.0%
	1855-Services	748,088	627,934	**120,154**	19.1%
	1860-Meters	873,921	862,512	11,409	1.3%
1500-General Plant	1908-Buildings and Fixtures				
	1915-Office Furniture and Equipment	122,774	122,774		
	1920-Computer Equipment - Hardware	312,587	251,086	**61,500**	24.5%
	1925-Computer Software	450,027	160,768	**289,259**	179.9%
	1930-Transportation Equipment	1,579,695	1,586,493	-6,798	(0.4%)
	1935-Stores Equipment	1,761	1,761		
	1940-Tools, Shop and Garage Equipment	234,229	234,229		
	1955-Communication Equipment	29,544	29,544		
	1960-Miscellaneous Equipment				
	1970-Load Management Controls - Customer Premises	254,912	254,912		
	1975-Load Management Controls - Utility Premises	64,873	64,873		
	1980-System Supervisory Equipment	498,536	498,536		
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-1,159,255	-965,152	**-194,103**	(20.1%)
TOTAL		**23,198,813**	**22,522,723**	**676,090**	**0.03**

Gross Asset Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	130,499	130,499		
	1806-Land Rights	10,809	10,809		
	1808-Buildings and Fixtures	372,714	372,714		
	1810-Leasehold Improvements	48,403	28,815	19,588	68.0%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,072,168	2,053,994	18,175	0.9%
	1830-Poles, Towers and Fixtures	7,940,798	7,823,153	**117,646**	1.5%
	1835-Overhead Conductors and Devices	2,014,783	1,767,114	**247,669**	14.0%
	1840-Underground Conduit	2,933,508	2,933,508		
	1845-Underground Conductors and Devices	247,842	204,849	42,993	21.0%
	1850-Line Transformers	3,020,928	2,843,663	**177,265**	6.2%
	1855-Services	627,934	513,721	**114,212**	22.2%
	1860-Meters	862,512	862,585	-73	(0.0%)
1500-General Plant	1908-Buildings and Fixtures				
	1915-Office Furniture and Equipment	122,774	122,774		
	1920-Computer Equipment - Hardware	251,086	245,589	5,497	2.2%
	1925-Computer Software	160,768	144,557	16,211	11.2%
	1930-Transportation Equipment	1,586,493	1,504,987	**81,506**	5.4%
	1935-Stores Equipment	1,761	1,761		
	1940-Tools, Shop and Garage Equipment	234,229	231,955	2,274	1.0%
	1955-Communication Equipment	29,544	29,544		
	1960-Miscellaneous Equipment				
	1970-Load Management Controls - Customer Premises	254,912	254,912		
	1975-Load Management Controls - Utility Premises	64,873	64,873		
	1980-System Supervisory Equipment	498,536	498,536		
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-965,152	-915,056	**-50,096**	(5.5%)
TOTAL		**22,522,723**	**21,729,857**	**792,866**	**0.04**

Gross Asset Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
1450-Distribution Plant	1805-Land	130,499	130,499	0	0.0%
	1806-Land Rights	10,809	8,703	2,106	24.2%
	1808-Buildings and Fixtures	372,714	486,068	**-113,354**	(23.3%)
	1810-Leasehold Improvements	28,815	9,540	19,275	202.0%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	2,053,994	1,892,012	**161,982**	8.6%
	1830-Poles, Towers and Fixtures	7,823,153	7,443,478	**379,675**	5.1%
	1835-Overhead Conductors and Devices	1,767,114	1,060,716	**706,398**	66.6%
	1840-Underground Conduit	2,933,508	2,854,963	**78,545**	2.8%
	1845-Underground Conductors and Devices	204,849	95,234	**109,615**	115.1%
	1850-Line Transformers	2,843,663	2,583,980	**259,683**	10.0%
	1855-Services	513,721	262,003	**251,718**	96.1%
	1860-Meters	862,585	826,266	36,319	4.4%
1500-General Plant	1908-Buildings and Fixtures		-193,827	**193,827**	100.0%
	1915-Office Furniture and Equipment	122,774	127,988	-5,214	(4.1%)
	1920-Computer Equipment - Hardware	245,589	219,999	25,590	11.6%
	1925-Computer Software	144,557	18,638	**125,919**	675.6%
	1930-Transportation Equipment	1,504,987	1,371,407	**133,580**	9.7%
	1935-Stores Equipment	1,761	1,761	0	0.0%
	1940-Tools, Shop and Garage Equipment	231,955	204,216	27,739	13.6%
	1955-Communication Equipment	29,544	26,661	2,883	10.8%
	1960-Miscellaneous Equipment		4,500	-4,500	(100.0%)
	1970-Load Management Controls - Customer Premises	254,912	250,715	4,197	1.7%
	1975-Load Management Controls - Utility Premises	64,873	64,873	0	0.0%
	1980-System Supervisory Equipment	498,536	485,610	12,926	2.7%
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-915,056	-367,732	**-547,324**	(148.8%)
TOTAL		**21,729,857**	**19,868,272**	**1,861,586**	**9.4%**

CAPITAL ASSET AMORTIZATION

The calculation of ORPC's annual amortization expense is presented in Exhibit 4, Tab 7, Schedule 1, Attachment 1. As described earlier,[1] ORPC has applied the half-year rule for rate-setting purposes – the following table summarizes annual expense amounts on this basis calculated on this basis:

Table 1: Annual Amortization Expense for Rate-Setting Purposes

2006 EDR Approved	$773,261
2006	$718,286
2007	$696,436
2008	$756,196
2009	$788,522
2010	$791,805

The 2010 forecast expense is slightly higher than the 2006 Board-approved amount, with a difference less than the materiality threshold. The year over year variances were also below this threshold, with the following exceptions:

- **2006 Actual vs 2006 Board-approved**: the decrease of $55K was primarily due to the use of the half-year rule (the 2006 Board-approved amount was based on full year depreciation of current year asset additions), and an increase in Contributed Capital which results in higher credits to depreciation expense.
- **2008 Actual vs 2007 Actual**: the increase of $60K was mostly due to investment in a new Customer Information System.

[1] see Exhibit 2, Tab 2, Schedule 3

FIXED ASSET CONTINUITIES

Attachment 1 presents the continuity statements for fixed assets, from the previously approved 2006 EDR balances to the projected 2010 year-end balances. The amortization expense amounts in these statements are consistent with the amounts calculated in accordance with the half-year rule for depreciation.[1] Explanations for annual balance changes in excess of the materiality threshold are provided in Schedule 1 (for Gross Assets) and Schedule 2 (for Accumulated Amortization) of this Tab / Exhibit.

The 'Ret./Other' column in the continuity statements represents amounts related to asset retirements or other adjustments included in the account balances:

Table 1: Fixed Asset Balance Adjustments

Year	Account	Amount	Description
2006 EDR → 2006 Actual	1808	(148,854)	Asset Reclassification
	1810	19,275	
	1820	129,579	
	1860	(21,124)	Scrap Meters (retirement)
	1908	193,827	Offset 2006 EDR adjustment [2]
	1915	(7,687)	Asset Retirement
	1925	37,731	Break out gross and accumulated amortization [3]
	1960	(4,500)	Offset 2006 EDR adjustment for balance reclassed from account #1565 (CDM)
	1995	(37,365)	Break out gross and accumulated amortization [4]
2006 Actual → 2007 Actual	1850	63,052	Asset Reclassification
	1855	(63,052)	
	1860	(8,078)	Scrap Meters (retirement)
2007 Actual → 2008 Actual	1808	(1,311)	Asset Reclassification
	1810	1,311	
	1860	(3,757)	Scrap Meters (retirement)
	1930	(219,864)	Vehicle replacements (retirement)
2009 Bridge → 2010 Test	1930	(168,857)	Vehicle replacements (retirement)

[1] see Exhibit 4, Tab 7, Schedule 1, Attachment 1

[2] see page 2 of Exhibit 2, Tab 3, Schedule 1

[3] see page 2 of Exhibit 1, Tab 4, Schedule 3

[4] *ibid.*

Fixed Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual: Additions	Ret./Other	Amortization	2006 Balance
1805-Land					
Gross Assets	130,499		0		130,499
Accumulated Amortization					
Net Book Value	130,499		0		130,499
1806-Land Rights					
Gross Assets	8,703	2,105	0		10,809
Accumulated Amortization	-4,879			-779	-5,657
Net Book Value	3,825	2,105	0	-779	5,152
1808-Buildings and Fixtures					
Gross Assets	486,068	35,500	-148,854		372,714
Accumulated Amortization	-213,314		0	-19,498	-232,813
Net Book Value	272,754	35,500	-148,854	-19,498	139,901
1810-Leasehold Improvements					
Gross Assets	9,540		19,275		28,815
Accumulated Amortization				-2,305	-2,305
Net Book Value	9,540		19,275	-2,305	26,510
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,892,012	32,403	129,579		2,053,994
Accumulated Amortization	-1,400,699		0	-105,898	-1,506,596
Net Book Value	491,313	32,403	129,580	-105,898	547,398
1830-Poles, Towers and Fixtures					
Gross Assets	7,443,478	379,674	0		7,823,153
Accumulated Amortization	-4,382,697		0	-684,665	-5,067,361
Net Book Value	3,060,781	379,674	1	-684,665	2,755,791
1835-Overhead Conductors and Devices					
Gross Assets	1,060,716	706,398	0		1,767,114
Accumulated Amortization	-118,417		0	-146,394	-264,810
Net Book Value	942,299	706,398	0	-146,394	1,502,304

Fixed Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other	Amortization	
1840-Underground Conduit					
Gross Assets	2,854,963	78,545	0		2,933,508
Accumulated Amortization	-1,396,761		-0	-215,724	-1,612,485
Net Book Value	1,458,202	78,545	-0	-215,724	1,321,023
1845-Underground Conductors and Devices					
Gross Assets	95,234	109,615	-0		204,849
Accumulated Amortization	-7,623		0	-64,169	-71,792
Net Book Value	87,611	109,615	0	-64,169	133,057
1850-Line Transformers					
Gross Assets	2,583,980	259,683	0		2,843,663
Accumulated Amortization	-1,377,695		0	-258,728	-1,636,423
Net Book Value	1,206,285	259,683	0	-258,728	1,207,240
1855-Services					
Gross Assets	262,003	251,718	0		513,721
Accumulated Amortization	-26,445		-0	-37,017	-63,463
Net Book Value	235,558	251,718	-0	-37,017	450,259
1860-Meters					
Gross Assets	826,266	57,443	-21,124		862,585
Accumulated Amortization	-416,131		21,124	-77,583	-472,590
Net Book Value	410,135	57,443	-0	-77,583	389,995
1908-Buildings and Fixtures					
Gross Assets	-193,827		193,827		
Accumulated Amortization	193,827		-193,827		
Net Book Value	1		-1		
1915-Office Furniture and Equipment					
Gross Assets	127,988	2,474	-7,687		122,774
Accumulated Amortization	-108,465		7,929	-7,274	-107,810
Net Book Value	19,523	2,474	242	-7,274	14,965

Fixed Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other	Amortization	
1920-Computer Equipment - Hardware					
Gross Assets	219,999	25,590	0		245,589
Accumulated Amortization	-221,828		0	-31,820	-253,648
Net Book Value	-1,829	25,590	1	-31,820	-8,058
1925-Computer Software					
Gross Assets	18,638	88,188	37,731		144,557
Accumulated Amortization			-37,731	-51,838	-89,570
Net Book Value	18,638	88,188	0	-51,838	54,988
1930-Transportation Equipment					
Gross Assets	1,371,407	133,580	-0		1,504,987
Accumulated Amortization	-1,172,237		0	-99,851	-1,272,088
Net Book Value	199,170	133,580	-0	-99,851	232,899
1935-Stores Equipment					
Gross Assets	1,761		0		1,761
Accumulated Amortization	-1,322			-346	-1,668
Net Book Value	439		0	-346	93
1940-Tools, Shop and Garage Equipment					
Gross Assets	204,216	27,738	0		231,955
Accumulated Amortization	-160,486		0	-22,326	-182,811
Net Book Value	43,730	27,738	1	-22,326	49,143
1955-Communication Equipment					
Gross Assets	26,661	2,883	-0		29,544
Accumulated Amortization	-22,645		-0	-6,600	-29,244
Net Book Value	4,016	2,883	-0	-6,600	300
1960-Miscellaneous Equipment					
Gross Assets	4,500		-4,500		
Accumulated Amortization					
Net Book Value	4,500		-4,500		

Fixed Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other	Amortization	
1970-Load Management Controls - Customer Premises					
Gross Assets	250,715	4,197	0		254,912
Accumulated Amortization	-212,678			-31,551	-244,229
Net Book Value	38,037	4,197	0	-31,551	10,683
1975-Load Management Controls - Utility Premises					
Gross Assets	64,873		0		64,873
Accumulated Amortization	-64,873				-64,873
Net Book Value	-0		0		
1980-System Supervisory Equipment					
Gross Assets	485,610	12,926	0		498,536
Accumulated Amortization	-344,379		-0	-53,265	-397,645
Net Book Value	141,231	12,926	0	-53,265	100,891
1995-Contributions and Grants - Credit					
Gross Assets	-367,732	-509,959	-37,365		-915,056
Accumulated Amortization			37,365	67,928	105,293
Net Book Value	-367,732	-509,959	0	67,928	-809,763
TOTAL					
Gross Assets	**19,868,272**	**1,700,701**	**160,885**		**21,729,857**
Accumulated Amortization	**-11,459,747**		**-165,139**	**-1,849,703**	**-13,474,589**
Net Book Value	**8,408,525**	**1,700,701**	**-4,254**	**-1,849,703**	**8,255,268**

Fixed Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	Additions	Ret./Other	Amortization	Balance
1805-Land					
Gross Assets	130,499				130,499
Accumulated Amortization					
Net Book Value	130,499				130,499
1806-Land Rights					
Gross Assets	10,809				10,809
Accumulated Amortization	-5,657			-306	-5,963
Net Book Value	5,152			-306	4,846
1808-Buildings and Fixtures					
Gross Assets	372,714				372,714
Accumulated Amortization	-232,813		0	-8,351	-241,164
Net Book Value	139,901		0	-8,351	131,550
1810-Leasehold Improvements					
Gross Assets	28,815	19,588			48,403
Accumulated Amortization	-2,305			-1,544	-3,850
Net Book Value	26,510	19,588		-1,544	44,553
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	2,053,994	18,175	-0		2,072,168
Accumulated Amortization	-1,506,596		0	-42,490	-1,549,085
Net Book Value	547,398	18,175	0	-42,490	523,083
1830-Poles, Towers and Fixtures					
Gross Assets	7,823,153	117,646	0		7,940,798
Accumulated Amortization	-5,067,361		0	-267,918	-5,335,279
Net Book Value	2,755,791	117,646	0	-267,918	2,605,519
1835-Overhead Conductors and Devices					
Gross Assets	1,767,114	247,669			2,014,783
Accumulated Amortization	-264,810		-0	-75,638	-340,449
Net Book Value	1,502,304	247,669	-0	-75,638	1,674,334

Fixed Asset Continuity Statements

	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other	Amortization	
1840-Underground Conduit					
Gross Assets	2,933,508				2,933,508
Accumulated Amortization	-1,612,485			-108,708	-1,721,193
Net Book Value	1,321,023			-108,708	1,212,315
1845-Underground Conductors and Devices					
Gross Assets	204,849	42,993			247,842
Accumulated Amortization	-71,792		0	-9,054	-80,846
Net Book Value	133,057	42,993	0	-9,054	166,996
1850-Line Transformers					
Gross Assets	2,843,663	114,212	63,052		3,020,928
Accumulated Amortization	-1,636,423		-0	-112,059	-1,748,482
Net Book Value	1,207,240	114,212	63,052	-112,059	1,272,446
1855-Services					
Gross Assets	513,721	177,265	-63,052		627,934
Accumulated Amortization	-63,463		-0	-22,833	-86,296
Net Book Value	450,259	177,265	-63,053	-22,833	541,638
1860-Meters					
Gross Assets	862,585	8,005	-8,078		862,512
Accumulated Amortization	-472,590		8,078	-31,886	-496,398
Net Book Value	389,995	8,005	-0	-31,886	366,114
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	122,774				122,774
Accumulated Amortization	-107,810			-2,130	-109,940
Net Book Value	14,965			-2,130	12,834

Fixed Asset Continuity Statements

	2006 Balance	2007 Changes Additions	Ret./Other	Amortization	2007 Balance
1920-Computer Equipment - Hardware					
Gross Assets	245,589	5,497			251,086
Accumulated Amortization	-253,648		-0	-14,448	-268,096
Net Book Value	-8,058	5,497	-0	-14,448	-17,009
1925-Computer Software					
Gross Assets	144,557	16,211			160,768
Accumulated Amortization	-89,570			-32,098	-121,667
Net Book Value	54,988	16,211		-32,098	39,101
1930-Transportation Equipment					
Gross Assets	1,504,987	81,506			1,586,493
Accumulated Amortization	-1,272,088		-0	-52,426	-1,324,515
Net Book Value	232,899	81,506	-0	-52,426	261,978
1935-Stores Equipment					
Gross Assets	1,761				1,761
Accumulated Amortization	-1,668			-138	-1,806
Net Book Value	93			-138	-45
1940-Tools, Shop and Garage Equipment					
Gross Assets	231,955	2,274	-0		234,229
Accumulated Amortization	-182,811		0	-9,053	-191,864
Net Book Value	49,143	2,274	0	-9,053	42,364
1955-Communication Equipment					
Gross Assets	29,544				29,544
Accumulated Amortization	-29,244			-50	-29,294
Net Book Value	300			-50	250
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Fixed Asset Continuity Statements

	2006 Balance	2007 Changes Additions	2007 Changes Ret./Other	2007 Changes Amortization	2007 Balance
1970-Load Management Controls - Customer Premises					
Gross Assets	254,912				254,912
Accumulated Amortization	-244,229			-4,390	-248,620
Net Book Value	10,683			-4,390	6,292
1975-Load Management Controls - Utility Premises					
Gross Assets	64,873				64,873
Accumulated Amortization	-64,873				-64,873
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	498,536				498,536
Accumulated Amortization	-397,645				-397,645
Net Book Value	100,891				100,891
1995-Contributions and Grants - Credit					
Gross Assets	-915,056	-50,096			-965,152
Accumulated Amortization	105,293			37,604	142,897
Net Book Value	-809,763	-50,096		37,604	-822,255
TOTAL					
Gross Assets	**21,729,857**	**800,943**	**-8,078**		**22,522,723**
Accumulated Amortization	**-13,474,589**		**8,077**	**-757,915**	**-14,224,427**
Net Book Value	**8,255,268**	**800,943**	**-1**	**-757,915**	**8,298,295**

Fixed Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
1805-Land					
Gross Assets	130,499				130,499
Accumulated Amortization					
Net Book Value	130,499				130,499
1806-Land Rights					
Gross Assets	10,809				10,809
Accumulated Amortization	-5,963			-306	-6,269
Net Book Value	4,846			-306	4,540
1808-Buildings and Fixtures					
Gross Assets	372,714	26,104	-1,311		397,506
Accumulated Amortization	-241,164		0	-8,586	-249,750
Net Book Value	131,550	26,104	-1,311	-8,586	147,756
1810-Leasehold Improvements					
Gross Assets	48,403		1,311		49,714
Accumulated Amortization	-3,850			-1,962	-5,812
Net Book Value	44,553		1,311	-1,962	43,902
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	2,072,168	12,288			2,084,456
Accumulated Amortization	-1,549,085		0	-42,997	-1,592,083
Net Book Value	523,083	12,288	0	-42,997	492,374
1830-Poles, Towers and Fixtures					
Gross Assets	7,940,798	88,870	-0		8,029,668
Accumulated Amortization	-5,335,279		-0	-260,276	-5,595,556
Net Book Value	2,605,519	88,870	-0	-260,276	2,434,112
1835-Overhead Conductors and Devices					
Gross Assets	2,014,783	202,916			2,217,699
Accumulated Amortization	-340,449		-0	-84,650	-425,099
Net Book Value	1,674,334	202,916	-0	-84,650	1,792,600

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other	Amortization	
1840-Underground Conduit					
Gross Assets	2,933,508				2,933,508
Accumulated Amortization	-1,721,193			-108,708	-1,829,901
Net Book Value	1,212,315			-108,708	1,103,607
1845-Underground Conductors and Devices					
Gross Assets	247,842	4,814	0		252,656
Accumulated Amortization	-80,846		-0	-10,010	-90,856
Net Book Value	166,996	4,814	-0	-10,010	161,800
1850-Line Transformers					
Gross Assets	3,020,928	59,677	-0		3,080,605
Accumulated Amortization	-1,748,482		0	-116,662	-1,865,144
Net Book Value	1,272,446	59,677	0	-116,662	1,215,461
1855-Services					
Gross Assets	627,934	120,154			748,088
Accumulated Amortization	-86,296		-0	-27,520	-113,817
Net Book Value	541,638	120,154	-0	-27,520	634,271
1860-Meters					
Gross Assets	862,512	15,166	-3,757		873,921
Accumulated Amortization	-496,398		3,757	-32,112	-524,753
Net Book Value	366,114	15,166	1	-32,112	349,168
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	122,774				122,774
Accumulated Amortization	-109,940			-2,130	-112,070
Net Book Value	12,834			-2,130	10,704

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other	Amortization	
1920-Computer Equipment - Hardware					
Gross Assets	251,086	61,500			312,587
Accumulated Amortization	-268,096		-0	-8,843	-276,938
Net Book Value	-17,009	61,500	-0	-8,843	35,649
1925-Computer Software					
Gross Assets	160,768	289,259			450,027
Accumulated Amortization	-121,667			-72,845	-194,513
Net Book Value	39,101	289,259		-72,845	255,515
1930-Transportation Equipment					
Gross Assets	1,586,493	213,067	-219,864		1,579,695
Accumulated Amortization	-1,324,515		212,640	-47,234	-1,159,109
Net Book Value	261,978	213,067	-7,224	-47,234	420,586
1935-Stores Equipment					
Gross Assets	1,761				1,761
Accumulated Amortization	-1,806		0	-0	-1,806
Net Book Value	-45		0	-0	-45
1940-Tools, Shop and Garage Equipment					
Gross Assets	234,229				234,229
Accumulated Amortization	-191,864			-6,903	-198,767
Net Book Value	42,364			-6,903	35,461
1955-Communication Equipment					
Gross Assets	29,544				29,544
Accumulated Amortization	-29,294				-29,294
Net Book Value	250				250
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other	Amortization	
1970-Load Management Controls - Customer Premises					
Gross Assets	254,912				254,912
Accumulated Amortization	-248,620			-2,134	-250,754
Net Book Value	6,292			-2,134	4,158
1975-Load Management Controls - Utility Premises					
Gross Assets	64,873				64,873
Accumulated Amortization	-64,873				-64,873
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	498,536				498,536
Accumulated Amortization	-397,645			-18,942	-416,586
Net Book Value	100,891			-18,942	81,950
1995-Contributions and Grants - Credit					
Gross Assets	-965,152	-194,103			-1,159,255
Accumulated Amortization	142,897			42,488	185,386
Net Book Value	-822,255	-194,103		42,488	-973,870
TOTAL					
Gross Assets	**22,522,723**	**899,711**	**-223,621**		**23,198,813**
Accumulated Amortization	**-14,224,427**		**216,397**	**-810,333**	**-14,818,363**
Net Book Value	**8,298,295**	**899,711**	**-7,224**	**-810,333**	**8,380,450**

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1805-Land					
Gross Assets	130,499				130,499
Accumulated Amortization					
Net Book Value	130,499				130,499
1806-Land Rights					
Gross Assets	10,809				10,809
Accumulated Amortization	-6,269			-306	-6,574
Net Book Value	4,540			-306	4,235
1808-Buildings and Fixtures					
Gross Assets	397,506	6,329			403,835
Accumulated Amortization	-249,750			-8,947	-258,697
Net Book Value	147,756	6,329		-8,947	145,138
1810-Leasehold Improvements					
Gross Assets	49,714				49,714
Accumulated Amortization	-5,812			-1,989	-7,800
Net Book Value	43,902			-1,989	41,914
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	2,084,456	478,615			2,563,071
Accumulated Amortization	-1,592,083			-43,865	-1,635,948
Net Book Value	492,374	478,615		-43,865	927,123
1830-Poles, Towers and Fixtures					
Gross Assets	8,029,668	78,052			8,107,720
Accumulated Amortization	-5,595,556			-251,798	-5,847,353
Net Book Value	2,434,112	78,052		-251,798	2,260,366
1835-Overhead Conductors and Devices					
Gross Assets	2,217,699	213,146			2,430,845
Accumulated Amortization	-425,099			-92,971	-518,069
Net Book Value	1,792,600	213,146		-92,971	1,912,775

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1840-Underground Conduit					
Gross Assets	2,933,508				2,933,508
Accumulated Amortization	-1,829,901			-108,708	-1,938,609
Net Book Value	1,103,607			-108,708	994,900
1845-Underground Conductors and Devices					
Gross Assets	252,656	77,683			330,339
Accumulated Amortization	-90,856			-11,660	-102,516
Net Book Value	161,800	77,683		-11,660	227,823
1850-Line Transformers					
Gross Assets	3,080,605	119,746			3,200,351
Accumulated Amortization	-1,865,144			-117,517	-1,982,661
Net Book Value	1,215,461	119,746		-117,517	1,217,691
1855-Services					
Gross Assets	748,088	127,263			875,351
Accumulated Amortization	-113,817			-32,469	-146,285
Net Book Value	634,271	127,263		-32,469	729,065
1860-Meters					
Gross Assets	873,921	2,847			876,768
Accumulated Amortization	-524,753			-23,039	-547,793
Net Book Value	349,168	2,847		-23,039	328,975
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	122,774				122,774
Accumulated Amortization	-112,070			-2,130	-114,201
Net Book Value	10,704			-2,130	8,574

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1920-Computer Equipment - Hardware					
Gross Assets	312,587	7,423			320,010
Accumulated Amortization	-276,938			-14,142	-291,080
Net Book Value	35,649	7,423		-14,142	28,930
1925-Computer Software					
Gross Assets	450,027	4,202			454,229
Accumulated Amortization	-194,513			-108,883	-303,396
Net Book Value	255,515	4,202		-108,883	150,833
1930-Transportation Equipment					
Gross Assets	1,579,695	14,240			1,593,935
Accumulated Amortization	-1,159,109			-45,468	-1,204,576
Net Book Value	420,586	14,240		-45,468	389,359
1935-Stores Equipment					
Gross Assets	1,761				1,761
Accumulated Amortization	-1,806				-1,806
Net Book Value	-45				-45
1940-Tools, Shop and Garage Equipment					
Gross Assets	234,229				234,229
Accumulated Amortization	-198,767			-6,630	-205,398
Net Book Value	35,461			-6,630	28,831
1955-Communication Equipment					
Gross Assets	29,544				29,544
Accumulated Amortization	-29,294				-29,294
Net Book Value	250				250
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1970-Load Management Controls - Customer Premises					
Gross Assets	254,912				254,912
Accumulated Amortization	-250,754			-839	-251,593
Net Book Value	4,158			-839	3,319
1975-Load Management Controls - Utility Premises					
Gross Assets	64,873				64,873
Accumulated Amortization	-64,873				-64,873
Net Book Value					
1980-System Supervisory Equipment					
Gross Assets	498,536	3,732			502,268
Accumulated Amortization	-416,586			-18,014	-434,600
Net Book Value	81,950	3,732		-18,014	67,668
1995-Contributions and Grants - Credit					
Gross Assets	-1,159,255	-119,236			-1,278,491
Accumulated Amortization	185,386			48,755	234,140
Net Book Value	-973,870	-119,236		48,755	-1,044,351
TOTAL					
Gross Assets	**23,198,813**	**1,014,042**			**24,212,855**
Accumulated Amortization	**-14,818,363**			**-840,620**	**-15,658,983**
Net Book Value	**8,380,450**	**1,014,042**		**-840,620**	**8,553,872**

Fixed Asset Continuity Statements

	2009 Balance	2010 Changes			2010 Balance
		Additions	Ret./Other	Amortization	
1805-Land					
Gross Assets	130,499	24,000			154,499
Accumulated Amortization					
Net Book Value	130,499	24,000			154,499
1806-Land Rights					
Gross Assets	10,809				10,809
Accumulated Amortization	-6,574			306	-6,269
Net Book Value	4,235			306	4,540
1808-Buildings and Fixtures					
Gross Assets	403,835	60,000			463,835
Accumulated Amortization	-258,697			9,674	-249,023
Net Book Value	145,138	60,000		9,674	214,812
1810-Leasehold Improvements					
Gross Assets	49,714				49,714
Accumulated Amortization	-7,800			1,989	-5,812
Net Book Value	41,914			1,989	43,902
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	2,563,071	150,000			2,713,071
Accumulated Amortization	-1,635,948			54,148	-1,581,800
Net Book Value	927,123	150,000		54,148	1,131,271
1830-Poles, Towers and Fixtures					
Gross Assets	8,107,720	103,470			8,211,190
Accumulated Amortization	-5,847,353			241,345	-5,606,008
Net Book Value	2,260,366	103,470		241,345	2,605,181
1835-Overhead Conductors and Devices					
Gross Assets	2,430,845	80,490			2,511,335
Accumulated Amortization	-518,069			94,729	-423,340
Net Book Value	1,912,775	80,490		94,729	2,087,994

Fixed Asset Continuity Statements

	2009 Balance	2010 Changes			2010 Balance
		Additions	Ret./Other	Amortization	
1840-Underground Conduit					
Gross Assets	2,933,508	51,000			2,984,508
Accumulated Amortization	-1,938,609			109,728	-1,828,881
Net Book Value	994,900	51,000		109,728	1,155,627
1845-Underground Conductors and Devices					
Gross Assets	330,339	82,350			412,689
Accumulated Amortization	-102,516			14,861	-87,655
Net Book Value	227,823	82,350		14,861	325,033
1850-Line Transformers					
Gross Assets	3,200,351	179,420			3,379,771
Accumulated Amortization	-1,982,661			120,971	-1,861,690
Net Book Value	1,217,691	179,420		120,971	1,518,082
1855-Services					
Gross Assets	875,351	87,200			962,551
Accumulated Amortization	-146,285			36,758	-109,527
Net Book Value	729,065	87,200		36,758	853,023
1860-Meters					
Gross Assets	876,768	24,000			900,768
Accumulated Amortization	-547,793			23,576	-524,216
Net Book Value	328,975	24,000		23,576	376,552
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	122,774	8,000			130,774
Accumulated Amortization	-114,201			2,176	-112,024
Net Book Value	8,574	8,000		2,176	18,750

Fixed Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
1920-Computer Equipment - Hardware					
Gross Assets	320,010	6,000			326,010
Accumulated Amortization	-291,080			14,100	-276,980
Net Book Value	28,930	6,000		14,100	49,030
1925-Computer Software					
Gross Assets	454,229	18,700			472,929
Accumulated Amortization	-303,396			103,639	-199,758
Net Book Value	150,833	18,700		103,639	273,172
1930-Transportation Equipment					
Gross Assets	1,593,935	302,000	-168,857		1,727,079
Accumulated Amortization	-1,204,576		168,857	63,535	-972,185
Net Book Value	389,359	302,000		63,535	754,893
1935-Stores Equipment					
Gross Assets	1,761				1,761
Accumulated Amortization	-1,806				-1,806
Net Book Value	-45				-45
1940-Tools, Shop and Garage Equipment					
Gross Assets	234,229	10,000			244,229
Accumulated Amortization	-205,398			7,130	-198,267
Net Book Value	28,831	10,000		7,130	45,961
1955-Communication Equipment					
Gross Assets	29,544	3,700			33,244
Accumulated Amortization	-29,294			370	-28,924
Net Book Value	250	3,700		370	4,320
1960-Miscellaneous Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					

Fixed Asset Continuity Statements

	2009 Balance	2010 Changes			2010 Balance
		Additions	Ret./Other	Amortization	
1970-Load Management Controls - Customer Premises					
Gross Assets	254,912				254,912
Accumulated Amortization	-251,593			839	-250,754
Net Book Value	3,319			839	4,158
1975-Load Management Controls - Utility Premises					
Gross Assets	64,873				64,873
Accumulated Amortization	-64,873			0	-64,873
Net Book Value				0	0
1980-System Supervisory Equipment					
Gross Assets	502,268	80,000			582,268
Accumulated Amortization	-434,600			15,796	-418,804
Net Book Value	67,668	80,000		15,796	163,464
1995-Contributions and Grants - Credit					
Gross Assets	-1,278,491	-103,000			-1,381,491
Accumulated Amortization	234,140			-53,200	180,941
Net Book Value	-1,044,351	-103,000		-53,200	-1,200,550
TOTAL					
Gross Assets	**24,212,855**	**1,167,330**	**-168,857**		**25,211,329**
Accumulated Amortization	**-15,658,983**		**168,857**	**862,470**	**-14,627,657**
Net Book Value	**8,553,872**	**1,167,330**		**862,470**	**10,583,672**

Tab 4 (of 6): Capital Plan

SUMMARY OF HISTORICAL CAPITAL EXPENDITURES

The following table summarizes ORPC's annual total capital expenditures:

Table 1: Capital Expenditure History

Year	Amount ($K)
2004	906
2005	675
2006	573
2007	801
2008	900

The decrease from 2004 to 2005 was mainly due to exceptionally high spending in 2004 for vehicle replacements. The decrease from 2005 to 2006 reflects unusually high spending in 2005 on line transformers due to the Almonte Hospital project. The increase from 2006 to 2007 arose mainly from a decline in capital contributions. The increase from 2007 to 2008 was mainly due to the implementation of a new Customer Information System.

Schedule 2 presents each capital project from 2004 to 2008, including a summary of the justification for the investment, a description of the project scope, and spending amounts by asset account. Schedule 3 presents the same information for capital projects in the 2009 Bridge year and 2010 test year.

Schedule 4 describes ORPC's investment planning practices.

HISTORICAL INVESTMENTS BY PROJECT

This schedule provides descriptions of actual capital project spending from 2004 to 2008. Attachment 1 presents annual summaries of capital spending by project and account.

Capital Additions for 2004

Account Description	USA Acct	Total
Land Rights	1806	$ 4,211
Building	1808	$ 11,800
Distribution Stations	1820	$ 16,856
Poles, Towers & Fixtures	1830	$ 182,165
Overhead Conductors & Devices	1835	$ 383,702
Underground Conduit	1840	$ 53,846
Underground Conductors & Devices	1845	$ 7,179
Line Transformers	1850	$ 85,578
Services	1855	$ 93,324
Meters	1860	$ 22,382
Office Furniture	1915	$ 4,947
Computer Hardware	1920	$ 6,445
Computer Software	1925	$ 21,910
Transportation Equipment	1930	$ 207,904
Misc. Tools & Equipment	1940	$ 14,648
Communication Equipment	1955	$ 765
Load Mgt Equip – Customer Premise	1970	$ 8,393
System Supervisory Equip	1980	$ 22,766
Contributed Capital	1995	-$ 242,630
TOTAL		**$ 906,191**

Project Description: #2004 – 01 Land Rights

Need: ORPC purchased easement rights from CPR for line reconstruction over railway crossing

Scope: The purchase of land rights (easement) for aerial line crossing on Ottawa Street in Almonte.

Capital Costs:

Account & Description	Amount
#1806 Land Rights	$ 4,211

Project Description: #2004 – 02 Building

Need: Building Number 2 on Frank Neighbor St. required tar and gravel roof replacement and additional insulation.

Scope: ORPC repaired Building 2.

Capital Costs:

Account & Description	Amount
#1808 Building	$ 11,800

Project Description: #2004 – 03 Distribution Stations

Need: Renovation of building

Scope: Upgrade of interior and insulation

Capital Costs:

Account & Description	Amount
#1820 Distribution Substations	$ 16,856

Project Description: #2004 – 04 Annual Pole Replacement

Need: ORPC replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of ORPC''s obligation to meet the safety standards of Reg 22/04.

Scope: Replacement of approximately 40 poles and transfer of conductor and equipment.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$ 24,911
#1835 Overhead Conductors & Devices	$137,228
Total	$162,139

Project Description: #2004 – 05 New Residential Development

Need: Service to new residential developments both overhead and underground servicing.

Scope: New services in subdivisions and scattered infill.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$11,054
#1835 Overhead Conductors & Devices	$45,724
#1845 Underground Conductors & Devices	$7,179
#1850 Line Transformers	$7,310
# 1995 Contributed Capital	-$52,756
Total	$18,511

Project Description: #2004 – 06 Commercial Development

Need: Service to new small scattered commercial development

Scope: Installation of poles and service conductors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$1,496
#1835 Overhead Conductors & Devices	$42,606
# 1995 Contributed Capital	-$38,489
Total	**$5,613**

Project Description: #2004 – 07 Pembroke St. West – New High School

Need: New primary supply to new French language school

Scope: Supply and installation of underground cable and padmounted transformer.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$25,746
#1835 Overhead Conductors & Devices	$50,994
#1850 Line Transformers	$18,110
# 1995 Contributed Capital	-$51,530
Total	**$43,320**

Project Description: #2004 – 08 Pembroke Court House

Need: Rearrange circuits to allow renovated and expansion of County Courthouse

Scope: Supply and installation of new line extension, and rearrangement of transformers and existing circuits

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$3,462
#1835 Overhead Conductors & Devices	$10,392
#1850 Line Transformers	$15,316
Total	**$29,170**

Project Description: #2004 – 09 Ottawa Street Rebuild

Need: Reconstruction of overhead line for provision of 44 kV looped supply in Almonte, to provide betterment of old line and improved reliability of sub transmission system.

Scope: First part of project to install new poles on Ottawa Street and start conductor installation.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$115,496
#1835 Overhead Conductors & Devices	$58,482
Total	**$173,978**

Project Description: #2004 – 10 Peter Street Rebuild

Need: Relocation of poles required by municipal road reconstruction

Scope: Relocate poles and rearrange conductor

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$38,276

Project Description: #2004 – 11 Metcalfe Farms Development

Need: Supply to new residential development in Almonte

Scope: Supply and installation of primary and secondary cable and padmounted transformers.

Capital Costs:

Account & Description	Amount
#1840 Underground Conduit	$53,846
#1850 Line Transformers	$1,996
#1995 Contributed Capital	-$67,905
Total	**-$12,063**

Project Description: #2004 – 12 Pembroke Pollution Centre

Need: Upgrade of electrical service for municipal waste water treatment plant

Scope: Supply and installation of primary cable and padmonted transformer.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$38,904
#1995 Contributed Capital	-$31,950
Total	$6,954

Project Description: #2004 – 13 Annual O/H and U/G Services & Upgrades

Need: Replacement of overhead and underground services that are identified in annual system inspection to improve reliability and safety.

Scope: Replacement of service conductors.

Capital Costs:

Account & Description	Amount
#1855 Services	$93,324

Project Description: #2004 – 14 Transformer Betterment

Need: Upgrading of transformer installation identified during annual inspection.

Scope: Transformer replacement

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$3,942

Project Description: #2004 – 15 Annual Meter Replacements and Upgrades

Need: Install meters for new services, meters beyond seal dates and upgrading of meter installations.

Scope: Meter and installation costs

Capital Costs:

Account & Description	Amount
#1860 Meters	$22,382

Project Description: #2004 – 16 Office Furniture

Need: Upgrading of office work stations

Scope: Replacement of work stations in billing and operations

Capital Costs:

Account & Description	Amount
#1915 Office Furniture	$4,947

Project Description: #2004 – 17 Computer Software – CIS System

Need: Adding functionality to customer billing system

Scope: Software enhancements to address regulatory requirements

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$21,910

Project Description: #2004 – 18 Transportation Equipment

Need: Vehicle upgrades

Scope: Chassis replacement and two small vehicle replacements

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$207,904

Project Description: #2004 – 19 Miscellaneous Tools & Equipment

Need: Acquisition of new and replacement tools and equipment for ongoing operation of distribution system.

Scope: Replace line tools

Capital Costs:

Account & Description	Amount
#1940 Miscellaneous Tools & Equipment	$14,648

Project Description: #2004 – 20 Communication Equipment

Need: Mobile radio system for operations department

Scope: Replace 1 radio

Capital Costs:

Account & Description	Amount
#1955 Communication Equipment	$765

Project Description: #2004 – 21 Load Mgt. Equip. – Customer Premise

Need: Load management study for customer usage patterns

Scope: Installation of load management recording devices in conjunction with Triacta

Capital Costs:

Account & Description	Amount
# 1970 Communication Equipment	$8,393

Project Description: #2004 – 22 System Supervisory Equipment

Need: Add and renew SCADA system for improved reliability of system

Scope: SCADA equipment acquisition

Capital Costs:

Account & Description	Amount
#1980 System Supervisory Equipment	$22,766

Project Description: #2004 – 23 Computer Hardware

Need: Upgrade technology

Scope: Purchase PC’s

Capital Costs:

Account & Description	Amount
# 1920 Computer Hardware	$6,445

Capital Additions for 2005

Account Description	USA Acct	Total
Building	1808	$ 29,599
Distribution Stations	1820	$ 11,901
Poles, Towers & Fixtures	1830	$ 78,045
Overhead Conductors & Devices	1835	$ 295,278
Underground Conduit	1840	$ 35,141
Underground Conductors & Devices	1845	$ 67,065
Line Transformers	1850	$ 159,723
Services	1855	$ 104,615
Meters	1860	$ 10,876
Computer Hardware	1920	$ 14,400
Computer Software	1925	$ 39,074
Transportation Equipment	1930	$ 3,023
Misc. Tools & Equipment	1940	$ 11,005
Communication Equipment	1955	$ 647
System Supervisory Equip	1980	$ 1,543
Contributed Capital	1995	-$187,410
TOTAL		$ 674,526

Project Description: #2005 – 1 Building

Need: Reconditioning/replacement of office roof

Scope: Roof replacement of office area

Capital Costs:

Account & Description	Amount
#1808 Building	$29,599

Project Description: #2005 – 2 Distribution Stations

Need: Betterments to improve reliability of distribution stations

Scope: Battery supply replacement

Capital Costs:

Account & Description	Amount
#1820 Distribution Stations	$11,901

Project Description: #2005 – 3 Annual Pole Replacements & Upgrades

Need: Replacement of poles identified in annual DSC system inspection

Scope: Betterment of pole lines for reliability

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$32,958
#1835 Overhead Conductors & Devices	$122,166
Total	**$155,124**

Project Description: #2005 – 4 New Residential Development

Need: Supply new residential developments and scattered services

Scope: Install primary and secondary cables and transformers

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$5,689
#1840 Underground Conduit	$1,436
#1845 Underground Conductors & Devices	$12,030
#1850 Line Transformers	$8,376
#1995 Contributed Capital	-$62,010
Total	**-$34,479**

Project Description: #2005 – 5 Commercial Development

Need: Supply of service to new commercial developments

Scope: Install line extensions, cable and transformers

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$12,139
#1835 Overhead Conductors & Devices	$4,571
#1845 Underground Conductors & Devices	$6,442
#1850 Line Transformers	$55,064
#1995 Contributed Capital	-$43,800
Total	**$34,416**

Project Description: #2005 – 6 Ottawa Street Rebuild

Need: Reconstruction of overhead line for provision of 44 kV looped supply in Almonte to provide betterment of old line and improved reliability of sub transmission system.

Scope: Continued work to install conductors

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$79,791

Project Description: #2005 – 7 Load Transfer Work

Need: Supply long term load transfer customer from ORPC supply, in accordance with regulatory requirements.

Scope: Re-configure connection to Pembroke Lumber

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$14,178
#1835 Overhead Conductors & Devices	$22,524
Total	**$36,702**

Project Description: #2005 – 8 Pembroke Court House

Need: Supply to new county courthouse building

Scope: Install line extension, cable and padmount transformer

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$10,684
#1835 Overhead Conductors & Devices	$34,811
#1845 Underground Conductors & Devices	$7,208
#1850 Line Transformers	$21,164
# 1995 Contributed Capital	-$81,600
Total	**-$7,733**

Project Description: #2005 – 9 Pembroke Street West – New School

Need: Complete work on project of 2004 for supply of Jeanne-Lajoie school

Scope: Line extension and tie-in of loop supply

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$23,227
#1840 Underground Conduit	$1,064
Total	**$24,291**

Project Description: #2005 – 10 Almonte Hospital

Need: New supply to expansion of Almonte Hospital

Scope: Provision of primary cable and two padmount transformers

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$8,086
#1835 Overhead Conductors & Devices	$2,499
#1840 Underground Conduit	$4,948
#1845 Underground Conductors & Devices	$41,385
#1850 Line Transformers	$71,928
Total	**$128,846**

Project Description: #2005 – 11 Metcalfe Farms Development

Need: Supply to new residential development area in Almonte

Scope: Supply and installation of duct

Capital Costs:

Account & Description	Amount
#1840 Underground Conduit	$27,693

Project Description: #2005 – 12 Annual O/H and U/G Services & Upgrades

Need: Replacement of overhead and underground services that are identified in annual system inspection to improve reliability and safety.

Scope: Replacement of service conductors.

Capital Costs:

Account & Description	Amount
#1855 Services	$104,615

Project Description: #2005 – 13 Transformer Betterments

Need: Upgrading of transformer installation identified during annual inspection.

Scope: Transformer replacement

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$3,191

Project Description: #2005 – 14 Annual Meter Replacements & Upgrades

Need: Installation of meters for new customers and/or seal expiries

Scope: Meter costs

Capital Costs:

Account & Description	Amount
#1860 Meters	$10,876

Project Description: #2005 – 15 Computer Software – CIS System

Need: Adding functionality to customer billing system

Scope: Cost of software and installation

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$23,146

Project Description: #2005 – 16 Computer Software – Other Software

Need: Upgrade of software

Scope: Purchase and installation of engineering and accounting software

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$15,928

Project Description: #2005 – 17 Transportation Equipment

Need: Major replacement for work equipment

Scope: Engine replacement

Capital Costs:

Account & Description	Amount
#1930 Transportation Eqiupment	$3,023

Project Description: #2005 – 18 Miscellaneous Tools & Equipment

Need: Acquisition of new and replacement tools and equipment for ongoing operation of distribution system.

Scope: Replace line tools

Capital Costs:

Account & Description	Amount
#1940 Miscellaneous Tools & Equipment	$11,005

Project Description: #2005 – 19 Communication Equipment

Need: Mobile radio system replacement of old equipment

Scope: Radio replacement

Capital Costs:

Account & Description	Amount
#1955 Communication Equipment	$647

Project Description: #2005 – 20 System Supervisory Equipment

Need: Main reliability of SCADA system

Scope: upgrade component

Capital Costs:

Account & Description	Amount
#1980 System Supervisory Equipment	$1,543

Project Description: #2005 – 21 Computer Hardware

Need: Replace back-up system

Scope: Purchase server

Capital Costs:

Account & Description	Amount
#1920 Computer Hardware	$14,400

Capital Additions for 2006

Account Description	USA Acct	Total
Distribution Stations	1820	$ 12,073
Poles, Towers & Fixtures	1830	$ 210,546
Overhead Conductors & Devices	1835	$ 219,269
Underground Conduit	1840	$ 16,481
Underground Conductors & Devices	1845	$ 38,962
Line Transformers	1850	$ 57,171
Services	1855	$ 100,441
Meters	1860	$ 35,376
Computer Hardware	1920	$ 7,966
Computer Software	1925	$ 38,159
Transportation Equipment	1930	$ 26,606
Misc. Tools & Equipment	1940	$ 9,409
Communication Equipment	1955	$ 1,854
Contributed Capital	1995	-$201,233
TOTAL		**$ 573,080**

Project Description: #2006 – 1 Distribution Stations

Need: reliability of station supply

Scope: Replace roof on station building

Capital Costs:

Account & Description	Amount
#1820 Distribution stations	$12,073

Project Description: #2006 – 2 Annual Pole Replacement

Need: ORPC replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of ORPC's obligation to meet the safety standards of Reg 22/04.

Scope: Replacement of approximately 40 poles and upgrading of conductor and equipment.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$55,122
#1835 Overhead Conductors & Devices	$57,500
Total	$112,622

Project Description: #2006 – 3 New Residential Development

Need: Service to new residential developments both overhead and underground servicing.

Scope: New services in subdivisions and scattered infill.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$8,987
#1835 Overhead Conductors & Devices	$18,874
#1845 Underground Conductors & Devices	$25,967
#1850 Line Transformers	$10,684
#1995 Contributed Capital	-$61,600
Total	$2,912

Project Description: #2006 – 4 Commercial Development

Need: Service to new small scattered commercial development

Scope: Installation of poles and service conductors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$31,094
#1835 Overhead Conductors & Devices	$45,607
#1840 Underground Conduit	$5,243
#1845 Underground Conductors & Devices	$3,632
#1850 Line Transformers	$13,930
#1995 Contributed Capital	-$81,633
Total	**$17,873**

Project Description: #2006 – 5 System Expansion

Need: Upgrade and replace line for reliability

Scope: Install new line conductor and convert to 3 phase

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$29,962

Project Description: #2006 – 6 Ottawa/Hope Street Rebuild

Need: Reconstruction of overhead line for provision of 44 kV looped supply in Almonte, to provide betterment of old line and improved reliability of sub transmission system.

Scope: Continued work to install conductors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$101,033
#1835 Overhead Conductors & Devices	$28,972
Total	**$130,005**

Project Description: #2006 – 7 D'Youville Development

Need: Servicing of new subdivision

Scope: Installation of underground cable and padmounted transformer along with single phase line extension.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$6,992
#1835 Overhead Conductors & Devices	$9,928
#1845 Underground Conductors & Devices	$9,363
#1995 Contributed Capital	-$25,500
Total	**$783**

Project Description: #2006 – 8 Metcalfe Farms Development

Need: Supply to new residential development in Almonte

Scope: Supply and installation of primary and secondary cable and padmounted transformers.

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$968
#1840 Underground Conduit	$11,238
#1850 Line Transformers	$11,040
#1995 Contributed Capital	-$32,500
Total	**-$9,254**

Project Description: #2006 – 9 Almonte Hospital

Need: New supply to expansion of Almonte Hospital

Scope: Final connection work for hospital

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$5,448

Project Description: #2006 – 10 Load Transfer Work

Need: Upgrade of rear lot secondary system

Scope: Replace overhead bus and transfer services

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$7,318
#1835 Overhead Conductors & Devices	$27,458
Total	**$34,776**

Project Description: #2006 – 11 Annual O/H and U/G Services & Upgrades

Need: Replacement of overhead and underground services that are identified in annual system inspection to improve reliability and safety.

Scope: Replacement of service conductors.

Capital Costs:

Account & Description	Amount
#1855 Services	$100,441

Project Description: #2006 – 12 Transformer Betterments

Need: Upgrading of transformer installation identified during annual inspection.

Scope: Transformer replacement

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$16,069

Project Description: #2006 – 13 Annual Meter Replacements & Upgrades

Need: Replacement of meters beyond seal dates and upgrading of meter installations.

Scope: Meter and installation costs

Capital Costs:

Account & Description	Amount
#1860 Meters	$35,376

Project Description: #2006 – 14 Computer Hardware

Need: Upgrade of technology

Scope: PC replacements

Capital Costs:

Account & Description	Amount
#1920 Computer Hardware	$7,966

Project Description: #2006 - 15 Computer Software – CIS System

Need: Upgrade to software

Scope: Engineering and CIS product upgrades

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$24,300

Project Description: #2006 – 16 Computer Software – Other Software

Need: Upgrade to accounting software

Scope: Completion of upgrade and installation of AccPac

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$13,859

Project Description: #2006 – 17 Transportation Equipment

Need: Replacement of fleet

Scope: Service van replaced

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$26,606

Project Description: #2006 – 18 Miscellaneous Tools & Equipment

Need: Acquisition of new and replacement tools and equipment for ongoing operation of distribution system.

Scope: Replace line tools

Capital Costs:

Account & Description	Amount
#1940 Miscellaneous Tools & Equipment	$9,409

Project Description: #2006 – 19 Communication Equipment

Need: Mobile radio system for operations department

Scope: Replace 1 radio

Capital Costs:

Account & Description	Amount
#1955 Communication Equipment	$1,854

Capital Additions for 2007

Account Description	USA Acct	Total
Building	1808	$ 19,588
Distribution Stations	1820	$ 18,175
Poles, Towers & Fixtures	1830	$ 117,645
Overhead Conductors & Devices	1835	$ 247,669
Underground Conductors & Devices	1845	$ 42,993
Line Transformers	1850	$ 114,212
Services	1855	$ 177,265
Meters	1860	$ 8,005
Computer Hardware	1920	$ 5,497
Computer Software	1925	$ 16,211
Transportation Equipment	1930	$ 81,506
Misc. Tools & Equipment	1940	$ 2,274
Contributed Capital	1995	- $ 50,096
TOTAL		**$ 800,944**

Project Description: #2007 – 1 Building

Need: Tar and gravel roof replacement

Scope: Labour and material to insulate and replace roof

Capital Costs:

Account & Description	Amount
#1808 Building	$19,588

Project Description: #2007 – 2 Distribution Stations

Need: Bring station grounding to present day safety standards

Scope: Upgrade station ground grid and install high resistance surface

Capital Costs:

Account & Description	Amount
#1820 Distribution Stations	$18,175

Project Description: #2007 – 3 Annual Pole Replacement

Need: Replacement of poles identified in annual DSC system inspection

Scope: Betterment of pole lines for reliability

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$64,288
#1835 Overhead Conductors & Devices	$101,076
Total	**$165,364**

Project Description: #2007 – 4 New Residential Development

Need: Supply new residential developments and scattered services

Scope: Install primary and secondary cables and transformers

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$3,324
#1835 Overhead Conductors & Devices	$34,872
#1845 Underground Conductors & Devices	$42,993
#1850 Line Transformers	$20,624
#1995 Contributed Capital	-$27,180
Total	**$74,633**

Project Description: #2007 – 5 Commercial Development

Need: Service to new small scattered commercial development

Scope: Installation of poles and service conductors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$11,763
#1835 Overhead Conductors & Devices	$5,999
#1850 Line Transformers	$23,286
#1995 Contributed Capital	-$22,916
Total	**$18,132**

Project Description: #2007 – 6 System Expansion

Need: Minor line extension to improve reliability of system

Scope: Labour and material to install poles

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$23,490

Project Description: #2007 – 7 Ottawa Street Rebuild

Need: Reconstruction of overhead line for provision of 44 kV looped supply in Almonte, to provide betterment of old line and improved reliability of sub transmission system.

Scope: Continued work to install conductors

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$32,234

Project Description: #2007 – 8 Peter Street Rebuild

Need: Demand work required by City for street reconstruction

Scope: Shift poles and realign conductor for road construction.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$9,180
#1835 Overhead Conductors & Devices	$11,790
#1850 Line Transformers	$2,830
Total	$23,800

Project Description: #2007 – 9 Load Transfer Work

Need: Long term load transfer

Scope: Complete 2006 load transfer work

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$3,003

Project Description: #2007 – 10 Pharma Plus

Need: Supply new commercial development

Scope: Supply and install transformers for store and raise conductor to maintain electrical clearance required by ESC.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$5,600
#1835 Overhead Conductors & Devices	$10,741
#1850 Line Transformers	$12,175
Total	**$28,516**

Project Description: #2007 – 11 Service Betterment

Need: Upgrade rear lot secondary

Scope: Remove weakened pole line

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$33,541

Project Description: #2007 – 12 D'Youville Drive Development

Need: Supply of new residential development

Scope: Supply and install underground cable and transformers for new residential development

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$5,134
#1850 Line Transformers	$6,028
Total	**$11,162**

Project Description: #2007 – 13 Pembroke Street East

Need: Improve reliability of 44 KV supply

Scope: Replace conductor installed in 1907 and increase capacity of line.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$7,250

Project Description: #2007 – 14 Transformer Betterments

Need: Upgrading of transformer installation identified during annual inspection.

Scope: Transformer replacement or relocation to new pole.

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$9,279
#1850 Line Transformers	$42,019
Total	**$51,298**

Project Description: #2007 – 15 Annual O/H and U/G Services & Upgrades

Need: Replacement of overhead and underground services that are identified in annual system inspection to improve reliability and safety.

Scope: Replacement of service conductors.

Capital Costs:

Account & Description	Amount
#1855 Services	$177,265

Project Description: #2007 – 16 Computer Hardware

Need: Upgrade of technology

Scope: PC replacements

Capital Costs:

Account & Description	Amount
#1920 Computer Hardware	$5,947

Project Description: #2007 – 17 Computer Software – Other Software

Need: Upgrade of technology

Scope: Accounting and engineering software

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$16,211

Project Description: #2007 – 18 Transportation Equipment

Need: Renewing of fleet

Scope: Purchase of chassis for double bucket truck

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$81,506

Project Description: #2007 – 19 Miscellaneous Tools & Equipment

Need: Acquisition of new or replacement tools and equipment for ongoing operation of distribution system.

Scope: Replace line tools

Capital Costs:

Account & Description	Amount
#1940 Miscellaneous Tools & Equipment	$2,274

Project Description: #2007 – 20 Annual Meter Replacements

Need: Replacement of meters beyond seal dates and upgrading of meter installations.

Scope: Meter and installation costs

Capital Costs:

Account & Description	Amount
#1860 Meters	$8,005

Capital Additions for 2008

Account Description	USA Acct	Total
Building	1808	$ 26,104
Distribution Stations	1820	$ 12,287
Poles, Towers & Fixtures	1830	$ 88,870
Overhead Conductors & Devices	1835	$ 202,917
Underground Conductors & Devices	1845	$ 4,814
Line Transformers	1850	$ 59,677
Services	1855	$ 120,154
Meters	1860	$ 15,166
Computer Hardware	1920	$ 61,500
Computer Software	1925	$ 289,259
Transportation Equipment	1930	$ 213,067
Contributed Capital	1995	- $194,102
Total		**$ 899,713**

Project Description: #2008 – 1 Building

Need: Tar and gravel roof replacement (Meter Shop)

Scope: Labour and material to insulate and replace roof

Capital Costs:

Account & Description	Amount
#1808 Building	$26,104

Project Description: #2008 – 2 Distribution Stations

Need: Update of heating system

Scope: Installation of heat pump

Capital Costs:

Account & Description	Amount
#1820 Distribution Stations	$12,287

Project Description: #2008 – 3 Annual Pole Replacement

Need: Replacement of poles identified in annual DSC system inspection

Scope: Betterment of pole lines for reliability

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$31,825
#1835 Overhead Conductors & Devices	$72,719
Total	**$104,544**

Project Description: #2008 – 4 New Residential Development

Need: Supply new residential developments and scattered services

Scope: Install primary and secondary cables and transformers

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$7,254
#1835 Overhead Conductors & Devices	$4,270
#1845 Underground Conductors & Devices	$4,814
#1850 Line Transformers	$12,243
#1995 Contributed Capital	-$82,590
Total	**$54,009**

Project Description: #2008 – 5 Commercial Development

Need: Service to new small scattered commercial development

Scope: Installation of poles and service conductor

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$2,847
#1835 Overhead Conductors & Devices	$0
#1850 Line Transformers	$2,846
#1995 Contributed Capital	-$54,312
Total	**-$48,619**

Project Description: #2008 – 6 Ottawa Street Rebuild

Need: Reconstruction of overhead line for provision of 44 kV looped supply in Almonte, to provide betterment of old line and improved reliability of sub transmission system.

Scope: Continued work to install conductors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$16,886
#1835 Overhead Conductors & Devices	$33,566
#1850 Line Transformers	$6,063
Total	**$56,515**

Project Description: #2008 – 7 Load Transfer Work

Need: Long term load transfer moved to ORPC supply

Scope: Install poles and conductors to transfer load

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$12,765
#1835 Overhead Conductors & Devices	$8,868
Total	$21,633

Project Description: #2008 – 8 Mary Street

Need: Betterment of overhead line to maintain reliability

Scope: Replace aged poles, conductor and services.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$10,547
#1835 Overhead Conductors & Devices	$22,676
#1850 Line Transformers	$4,045
Total	$37,268

Project Description: #2008 – 9 Miller Street

Need: Betterment of overhead line to maintain reliability

Scope: Replace aged poles, conductor and services.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$6,746
#1835 Overhead Conductors & Devices	$26,739
#1850 Line Transformers	$5,531
Total	$39,016

Project Description: #2008 – 10 Pembroke Street East

Need: Improve reliability of 44 KV supply

Scope: Replace conductor installed in 1907 and increase capacity of line.

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$34,079

Project Description: #2008 – 11 Transformer Betterments

Need: Upgrading of transformer installation identified during annual inspection.

Scope: Transformer replacement or relocation to new pole.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$28,949

Project Description: #2008 – 12 Annual O/H and U/G Services & Upgrades

Need: Replacement of overhead and underground services that are identified in annual system inspection to improve reliability and safety.

Scope: Replacement of service conductor.

Capital Costs:

Account & Description	Amount
#1855 Services	$120,154

Project Description: #2008 – 13 Computer Hardware

Need: Upgrade of technology

Scope: Replacement of servers for CIS upgrade

Capital Costs:

Account & Description	Amount
#1920 Computer Hardware	$61,500

Project Description: #2008 – 14 Computer Software – CIS System

Need: Upgrade of system to replace vendor that left Ontario market

Scope: Upgrade of CIS system

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$286,185
#1995 Contributed Capital	-$57,200
Total	**$228,985**

Project Description: #2008 – 15 Computer Software – Other Software

Need: Upgrade of system technology

Scope: Upgrade PC software

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$3,074

Project Description: #2008 – 16 Transportation Equipment

Need: Renewing of fleet

Scope: Purchase of double bucket unit

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$213,067

Project Description: #2008 – 17 Annual Meter Replacements

Need: Replacement of meters beyond seal dates and upgrading of meter installations.

Scope: Meter and installation costs

Capital Costs:

Account & Description	Amount
#1860 Meters	$15,166

Historical Capital Project Tables

Year: **2004**

Project Number	Project Description	1806 Land Rights	1808 Building	1820 Distribution Stations	1830 Poles,Towers Fixtures	1835 Overhead Conductors & Devices	1840 Underground Conduit	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1915 Office Furniture	1920 Computer Hardware	1925 Computer Software
2004-01	Land Rights	4,211												
2004-02	Building		11,800											
2004-03	Distribution Stations			16,856										
2004-04	Annual Pole Replacement				24,911	137,228								
2004-05	New Residential Development				11,054	45,724		7,179	7,310					
2004-06	Commercial Development				1,496	42,606								
2004-07	Pembroke St. West - New High School				25,746	50,994			18,110					
2004-08	Pembroke Court House				3,462	10,392			15,316					
2004-09	Ottawa Street Rebuild				115,496	58,482								
2004-10	Peter St. Rebuild					38,276								
2004-11	Metcalfe Farms Development						53,846		1,996					
2004-12	Pembroke Pollution Centre								38,904					
2004-13	Annual O/H and U/G Services & Upgrades									93,324				
2004-14	Transformer Betterment								3,942					
2004-15	Annual Meter Replacements & Upgrades										22,382			
2004-16	Office Furniture											4,947		
2004-17	Computer Software - CIS System													21,910
2004-18	Transportation Equipment													
2004-19	Miscellaneous Tools & Equipment													
2004-20	Communication Equipment													
2004-21	Load Mgt Equip - Customer Premise													
2004-22	System Supervisory Equipmt													
2004-23	Computer Hardware - PCS												6,445	
	TOTAL	**4,211**	**11,800**	**16,856**	**182,165**	**383,702**	**53,846**	**7,179**	**85,578**	**93,324**	**22,382**	**4,947**	**6,445**	**21,910**

Historical Capital Project Tables

Year: **2004**

Project Number	Project Description	1930 Transportation Equipment	1940 Misc Tools & Equipment	1955 Communication Equipment	1970 Load Mgmt - Customer Premises	1980 System Supervisory Equipment	1995 Contributed Capital	TOTAL
2004-01	Land Rights							**4,211**
2004-02	Building							**11,800**
2004-03	Distribution Stations							**16,856**
2004-04	Annual Pole Replacement							**162,139**
2004-05	New Residential Development						-52,756	**18,511**
2004-06	Commercial Development						-38,489	**5,613**
2004-07	Pembroke St. West - New High School						-51,530	**43,320**
2004-08	Pembroke Court House							**29,170**
2004-09	Ottawa Street Rebuild							**173,978**
2004-10	Peter St. Rebuild							**38,276**
2004-11	Metcalfe Farms Development						-67,905	**-12,063**
2004-12	Pembroke Pollution Centre						-31,950	**6,954**
2004-13	Annual O/H and U/G Services & Upgrades							**93,324**
2004-14	Transformer Betterment							**3,942**
2004-15	Annual Meter Replacements & Upgrades							**22,382**
2004-16	Office Furniture							**4,947**
2004-17	Computer Software - CIS System							**21,910**
2004-18	Transportation Equipment	207,904						**207,904**
2004-19	Miscellaneous Tools & Equipment		14,648					**14,648**
2004-20	Communication Equipment			765				**765**
2004-21	Load Mgt Equip - Customer Premise				8,393			**8,393**
2004-22	System Supervisory Equipmt					22,766		**22,766**
2004-23	Computer Hardware - PCS							**6,445**
	TOTAL	**207,904**	**14,648**	**765**	**8,393**	**22,766**	**-242,630**	**906,191**

Historical Capital Project Tables

Year: **2005**

Project Number	Project Description	1808 Building	1820 Distribution Stations	1830 Poles,Towers & Fixtures	1835 Overhead Conductors & Devices	1840 Underground Conduit	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1920 Computer Hardware	1925 Computer Software	1930 Transportation Equipment
2005-01	Building	29,599											
2005-02	Distribution Stations		11,901										
2005-03	Annual Pole Replacements & Upgrades			32,958	122,166								
2005-04	New Residential Development				5,689	1,436	12,030	8,376					
2005-05	Commercial Development			12,139	4,571		6,442	55,064					
2005-06	Ottawa Street Rebuild				79,791								
2005-07	Load Transfer Work			14,178	22,524								
2005-08	Pembroke Court House			10,684	34,811		7,208	21,164					
2005-09	Pembroke St. West - New School				23,227	1,064							
2005-10	Almonte Hospital			8,086	2,499	4,948	41,385	71,928					
2005-11	Metcalfe Farms Development					27,693							
2005-12	Annual O/H and U/G Services & Upgrades								104,615				
2005-13	Transformer Betterments							3,191					
2005-14	Annual Meter Replacements & Upgrades									10,876			
2005-15	Computer Software - CIS System											23,146	
2005-16	Computer Software - Other Software											15,928	
2005-17	Transportation Equipment												3,023
2005-18	Miscellaneous Tools & Equipment												
2005-19	Communication Equipment												
2005-20	System Supervisory Equipment												
2005-21	Computer Hardware										14,400		
	TOTAL	**29,599**	**11,901**	**78,045**	**295,278**	**35,141**	**67,065**	**159,723**	**104,615**	**10,876**	**14,400**	**39,074**	**3,023**

Historical Capital Project Tables

Year: **2005**

Project Number	Project Description	1940 Misc Tools & Equipment	1955 Communication Equipment	1980 System Supervisory Equipment	1995 Contributed Capital	TOTAL
2005-01	Building					**29,599**
2005-02	Distribution Stations					**11,901**
2005-03	Annual Pole Replacements & Upgrades					**155,124**
2005-04	New Residential Development				-62,010	**-34,479**
2005-05	Commercial Development				-43,800	**34,416**
2005-06	Ottawa Street Rebuild					**79,791**
2005-07	Load Transfer Work					**36,702**
2005-08	Pembroke Court House				-81,600	**-7,733**
2005-09	Pembroke St. West - New School					**24,291**
2005-10	Almonte Hospital					**128,846**
2005-11	Metcalfe Farms Development					**27,693**
2005-12	Annual O/H and U/G Services & Upgrades					**104,615**
2005-13	Transformer Betterments					**3,191**
2005-14	Annual Meter Replacements & Upgrades					**10,876**
2005-15	Computer Software - CIS System					**23,146**
2005-16	Computer Software - Other Software					**15,928**
2005-17	Transportation Equipment					**3,023**
2005-18	Miscellaneous Tools & Equipment	11,005				**11,005**
2005-19	Communication Equipment		647			**647**
2005-20	System Supervisory Equipment			1,543		**1,543**
2005-21	Computer Hardware					**14,400**
	TOTAL	**11,005**	**647**	**1,543**	**-187,410**	**674,526**

Historical Capital Project Tables

Year: **2006**

Project Number	Project Description	1820 Distribution Stations	1830 Poles, Towers & Fixtures	1835 Overhead Conductors & Devices	1840 Underground Conduit	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1920 Computer Hardware	1925 Computer Software	1930 Transportation Equipment
2006-01	Distribution Stations	12,073										
2006-02	Annual Pole Replacement		55,122	57,500								
2006-03	New Residential Development		8,987	18,874		25,967	10,684					
2006-04	Commercial Development		31,094	45,607	5,243	3,632	13,930					
2006-05	System Expansion			29,962								
2006-06	Ottawa/Hope Street Rebuild		101,033	28,972								
2006-07	D'Youville Development		6,992	9,928		9,363						
2006-08	Metcalfe Farms Development			968	11,238		11,040					
2006-09	Almonte Hospital						5,448					
2006-10	Load Transfer Work		7,318	27,458								
2006-11	Annual O/H and U/G Services & Upgrades							100,441				
2006-12	Transformer Betterments						16,069					
2006-13	Annual Meter Replacements & Upgrades								35,376			
2006-14	Computer Hardware									7,966		
2006-15	Computer Software - CIS System										24,300	
2006-16	Computer Software - Other Software										13,859	
2006-17	Transportation Equipment											26,606
2006-18	Miscellaneous Tools & Equipment											
2006-19	Communication Equipment											
	TOTAL	**12,073**	**210,546**	**219,269**	**16,481**	**38,962**	**57,171**	**100,441**	**35,376**	**7,966**	**38,159**	**26,606**

Historical Capital Project Tables

Year: **2006**

Project Number	Project Description	1940 Miscellaneous Tools & Equipment	1955 Communication Equipment	1995 Contributed Capital	TOTAL
2006-01	Distribution Stations				**12,073**
2006-02	Annual Pole Replacement				**112,622**
2006-03	New Residential Development			-61600	**2,912**
2006-04	Commercial Development			-81633	**17,873**
2006-05	System Expansion				**29,962**
2006-06	Ottawa/Hope Street Rebuild				**130,005**
2006-07	D'Youville Development			-25500	**783**
2006-08	Metcalfe Farms Development			-32500	**-9,254**
2006-09	Almonte Hospital				**5,448**
2006-10	Load Transfer Work				**34,776**
2006-11	Annual O/H and U/G Services & Upgrades				**100,441**
2006-12	Transformer Betterments				**16,069**
2006-13	Annual Meter Replacements & Upgrades				**35,376**
2006-14	Computer Hardware				**7,966**
2006-15	Computer Software - CIS System				**24,300**
2006-16	Computer Software - Other Software				**13,859**
2006-17	Transportation Equipment				**26,606**
2006-18	Miscellaneous Tools & Equipment	9,409			**9,409**
2006-19	Communication Equipment		1854		**1,854**
	TOTAL	**9,409**	**1,854**	**-201,233**	**573,080**

Historical Capital Project Tables

Year: **2007**

Project Number	Project Description	1808 Building	1820 Distribution Stations	1830 Poles, Towers & Fixtures	1835 Overhead Conductors & Devices	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1920 Computer Hardware	1925 Computer Software
2007-01	Building	19,588									
2007-02	Distribution Stations		18,175								
2007-03	Annual Pole Replacement			64,288	101,076						
2007-04	New Residential Development			3,324	34,872	42,993	20,624				
2007-05	Commercial Development			11,763	5,999		23,286				
2007-06	System Expansion			23,490							
2007-07	Ottawa Street Rebuild				32,234						
2007-08	Peter Street Rebuild			9,180	11,790		2,830				
2007-09	Load Transfer Work				3,003						
2007-10	Pharma Plus			5,600	10,741		12,175				
2007-11	Boundary Rd - Rear Lot Better.				33,541						
2007-12	D'Youville Drive Development				5,134		6,028				
2007-13	Pembroke St. East						7,250				
2007-14	Transformer Betterments				9,279		42,019				
2007-15	Annual O/H and U/G Services & Upgrades							177,265			
2007-16	Computer Hardware									5,497	
2007-17	Computer Software - Other Software										16,211
2007-18	Transportation Equipment										
2007-19	Miscellaneous Tools & Equipment										
2007-20	Annual Meter Additions								8,005		
	TOTAL	**19,588**	**18,175**	**117,645**	**247,669**	**42,993**	**114,212**	**177,265**	**8,005**	**5,497**	**16,211**

Historical Capital Project Tables

Year: **2007**

Project Number	Project Description	1930 Transportation Equipment	1940 Misc Tools & Equipment	1995 Contributed Capital	TOTAL
2007-01	Building				**19,588**
2007-02	Distribution Stations				**18,175**
2007-03	Annual Pole Replacement				**165,364**
2007-04	New Residential Development			-27,180	**74,633**
2007-05	Commercial Development			-22,916	**18,132**
2007-06	System Expansion				**23,490**
2007-07	Ottawa Street Rebuild				**32,234**
2007-08	Peter Street Rebuild				**23,800**
2007-09	Load Transfer Work				**3,003**
2007-10	Pharma Plus				**28,516**
2007-11	Boundary Rd - Rear Lot Better.				**33,541**
2007-12	D'Youville Drive Development				**11,162**
2007-13	Pembroke St. East				**7,250**
2007-14	Transformer Betterments				**51,298**
2007-15	Annual O/H and U/G Services & Upgrades				**177,265**
2007-16	Computer Hardware				**5,497**
2007-17	Computer Software - Other Software				**16,211**
2007-18	Transportation Equipment	81,506			**81,506**
2007-19	Miscellaneous Tools & Equipment		2,274		**2,274**
2007-20	Annual Meter Additions				**8,005**
	TOTAL	**81,506**	**2,274**	**-50,096**	**800,944**

Historical Capital Project Tables

Year: **2008**

Project Number	Project Description	1808 Building	1820 Distribution Stations	1830 Poles, Towers & Fixtures	1835 Overhead Conductors & Devices	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1920 Computer Hardware	1925 Computer Software
2008-01	Building	26,104									
2008-02	Distribution Stations		12,287								
2008-03	Annual Pole Replacement			31,825	72,719						
2008-04	New Residential Development			7,254	4,270	4,814	12,243				
2008-05	Commercial Development			2,847			2,846				
2008-06	Ottawa Street Rebuild			16,886	33,566		6,063				
2008-07	Load Transfer Work			12,765	8,868						
2008-08	Mary St.			10,547	22,676		4,045				
2008-09	Miller St.			6,746	26,739		5,531				
2008-10	Pembroke St. East				34,079						
2008-11	Transformer Betterments						28,949				
2008-12	Annual O/H and U/G Services & Upgrades							120,154			
2008-13	Computer Hardware									61,500	
2008-14	Computer Software - CIS System										286,185
2008-15	Computer Software - Other Software										3,074
2008-16	Transportation Equipment										
2008-17	Annual meter Additions								15,166		
	TOTAL	**26,104**	**12,287**	**88,870**	**202,917**	**4,814**	**59,677**	**120,154**	**15,166**	**61,500**	**289,259**

Historical Capital Project Tables

Year: **2008**

Project Number	Project Description	1930 Transportation Equipment	1995 Contributed Capital	TOTAL
2008-01	Building			**26,104**
2008-02	Distribution Stations			**12,287**
2008-03	Annual Pole Replacement			**104,544**
2008-04	New Residential Development		-82,590	**-54,009**
2008-05	Commercial Development		-54,312	**-48,619**
2008-06	Ottawa Street Rebuild			**56,515**
2008-07	Load Transfer Work			**21,633**
2008-08	Mary St.			**37,268**
2008-09	Miller St.			**39,016**
2008-10	Pembroke St. East			**34,079**
2008-11	Transformer Betterments			**28,949**
2008-12	Annual O/H and U/G Services & Upgrades			**120,154**
2008-13	Computer Hardware			**61,500**
2008-14	Computer Software - CIS System		-57,200	**228,985**
2008-15	Computer Software - Other Software			**3,074**
2008-16	Transportation Equipment	213,067		**213,067**
2008-17	Annual meter Additions			**15,166**
	TOTAL	**213,067**	**-194,102**	**899,713**

FORECAST INVESTMENTS BY PROJECT

This schedule provides descriptions of capital project spending for 2009 and 2010. Attachment 1 presents annual summaries of capital spending by project and account.

Capital Additions for 2009

Account Description	USA Acct	Total
Building	1808	$ 6,329
Distribution Stations	1820	$ 478,615
Poles, Towers & Fixtures	1830	$ 78,052
Overhead Conductors & Devices	1835	$ 213,146
Underground Conductors & Devices	1845	$ 77,683
Line Transformers	1850	$ 119,746
Services	1855	$ 127,263
Meters	1860	$ 2,847
Computer Hardware	1920	$ 7,423
Computer Software	1925	$ 4,202
Transportation Equipment	1930	$ 14,240
Supervisory Control and Data Acquisition	1980	$ 3,732
Contributed Capital	1995	-$ 119,236
Total		$ 1,014,042

Project Description: #2009 – 1 Building

Need: Improve energy efficiency of building

Scope: Insulate exterior wall of stores warehouse

Capital Costs:

Account & Description	Amount
#1808 Building	$ 6,329

Project Description: #2009 – 2 Distribution Stations

Need: Station Upgrade - upgrading of 1930 vintage station

Scope: Power transformer, switchgear and civil works

Capital Costs:

Account & Description	Amount
#1820 Distribution Stations	$478,615

Project Description: #2009 – 3 New Residential Development

Need: Service of new residential developments

Scope: Installation of poles, conductors and transformers

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$7,800
#1835 Overhead Conductors & Devices	$16,400
#1845 Underground Conductors & Devices	$60,500
#1850 Line Transformers	$22,300
#1855 Services	$42,100
#1995 Contributed Capital	-$119,236
Total	**$29,864**

Project Description: #2009 – 4 Commercial Development

Need: Service of new commercial developments

Scope: Installation of poles, conductor and transformers

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$2,500
#1835 Overhead Conductors & Devices	$10,500
#1845 Underground Conductors	$13,300
#1850 Line Transformers	$62,000
#1855 Services	$1,000
Total	**$89,300**

Project Description: #2009 – 5 System Expansion

Need: Reinforcement and expansion of distribution system

Scope: Conductor replacements and extension of overhead system

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$10,000
#1835 Overhead Conductors & Devices	$39,246
#1850 Line Transformers	$2,000
Total	**$51,246**

Project Description: #2009 – 6 Load Transfer Work

Need: Line extension for reducing long term load transfers

Scope: Overhead line extension

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$10,752
#1835 Overhead Conductors & Devices	$63,000
#1850 Line Transformers	$11,300
Total	**$85,052**

Project Description: #2009 –7 Road Relocation

Need: Distribution system relocations to accommodate road work

Scope: Relocate poles and conductors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$21,000
#1835 Overhead Conductors & Devices	$4,000
#1850 Line Transformers	$2,146
#1855 Services	$17,000
Total	**$44,146**

Project Description: #2009 – 8 Line Betterments

Need: Upgrading Overhead Lines for Reliability

Scope: Refurbishing lines to renew poles, and conductor

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$26,000
#1835 Overhead Conductors & Devices	$80,000
#1850 Line Transformers	$5,000
Total	**$111,000**

Project Description: #2009 – 9 New Meters and Metering Equipment

Need: Installation of new metering

Scope: Installation of metering equipment not within Smart meter program

Capital Costs:

Account & Description	Amount
#1860 Metering	$2,847

Project Description: #2009 – 10 Transformer Betterments

Need: Replacement of deteriorated transformers

Scope: Replace overhead and padmounted transformers

Capital Costs:

Account & Description	Amount
#1845 Underground Conductors and Devices	$3,883
#1850 Line Transformers	$15,000
Total	**$18,883**

Project Description: #2009 – 11 Annual O/H and U/G Services & Upgrades

Need: Installation of new services and Upgrade of services identified in annual DSC inspection

Scope: Replacement of service conductor

Capital Costs:

Account & Description	Amount
#1855 Services	$67,163

Project Description: #2009 – 12 Computer Hardware

Need: Update technology

Scope: Replace PC computers

Capital Costs:

Account & Description	Amount
#1920 Computer Hardware	$7,423

Project Description: #2009 – 13 Computer Software – CIS System

Need: Update technology

Scope: CIS module upgrades to meet regulatory changes

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$4,202

Project Description: #2009 – 14 Transportation Equipment

Need: Updating of Fleet

Scope: Aerial device overall.

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$14,240

Project Description: #2009 – 15 SCADA

Need: Update SCADA System

Scope: Printer replacement

Capital Costs:

Account & Description	Amount
#1980 System Supervisory Equipment	$3,732

Capital Additions for 2010

Account Description	USA Acct	Total
Land	1805	$ 24,000
Building	1808	$ 60,000
Distribution Stations	1820	$ 150,000
Poles, Towers & Fixtures	1830	$ 103,470
Overhead Conductors & Devices	1835	$ 80,490
Underground Conduit	1840	$ 51,000
Underground Conductors & Devices	1845	$ 82,350
Line Transformers	1850	$ 179,420
Services	1855	$ 87,200
Meters	1860	$ 24,000
Furniture	1915	$ 8,000
Computer Hardware	1920	$ 6,000
Computer Software	1925	$ 18,700
Transportation Equipment	1930	$ 302,000
Tools & Equipment	1940	$ 10,000
Communications Equipment	1955	$ 3,700
System Supervisory Equipment	1980	$ 80,000
Contributed Capital	1995	-$ 103,000
Total		$ 1,167,330

Project Description: #2010 – 1 Station Grounding

Need: Bring station to present safety standard

Scope: Upgrade ground grid

Capital Costs:

Account & Description	Amount
#1805 Land	$24,000
#1808 Building	46,000
Total	**$30,000**

Project Description: #2010 – 2 Sub Stations Betterment

Need: Upgrade station

Scope: Complete work in replacement 44kv station

Capital Costs:

Account & Description	Amount
#1820 Distribution Stations	$150,000

Project Description: #2010 – 3 Annual Pole Replacement

Need: Betterment for aging poles

Scope: Replace poles identified in annual inspection

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$77,100
#1835 Overhead Conductors & Devices	$16,000
Total	**$93,100**

Project Description: #2010 – 4 New Residential Developments

Need: Meet demand of new developments

Scope: Service to residential development

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$5,270
#1835 Overhead Conductors & Devices	$5,340
#1845 Underground Conductors & Devices	$49,650
#1850 Line Transformers	$31,400
#1855 Services	$24,900
#1860 Meters	$6,900
# 1995 Capital Contributions	-$57,000
Total	**$66,460**

Project Description: #2010 – 5 Commercial Development

Need: Meet demand for new commercial development

Scope: Service to commercial development

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$12,700
#1845 Underground Conductors & Devices	$12,700
#1850 Line Transformers	$54,800
#1860 Meters	$11,600
#1995 Contributed Capital	-$46,000
Total	**$45,800**

Project Description: #2010 – 6 Office Building Improvements

Need: Building structure update

Scope: Accessibility study and energy retrofitting

Capital Costs:

Account & Description	Amount
#1808 Building	$14,000

Project Description: #2010 – 7 Construct Cold Storage Building

Need: Secure storage for stores material and work equipment

Scope: Construct 40' storage building

Capital Costs:

Account & Description	Amount
#1808 Building	$40,000

Project Description: #2010 – 8 Pembroke St Rebuild

Need: System betterment

Scope: Rebuild overhead pole line

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$17,100
#1835 Overhead Conductors & Devices	$15,700
#1850 Line Transformers	$1,700
#1855 Services	$3,900
Total	**$38,400**

Project Description: #2010 – 9 Hope Street Completion

Need: System betterment

Scope: Complete rebuild of overhead pole line

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers & Fixtures	$4,000
#1835 Overhead Conductors & Devices	$11,600
#1850 Line Transformers	$3,120
#1855 Services	$5,400
Total	**$24,120**

Project Description: #2010 – 10 Pembroke Alexander Street

Need: Plant relocation for roadwork

Scope: Remove overhead system and install underground plant

Capital Costs:

Account & Description	Amount
#1840 Underground conduit	$51,000
#1845 Underground Conductors & Devices	$20,000
#1850 Line Transformers	$70,000
Total	**$141,000**

Project Description: #2010 – 11 Almonte 44kv A/B

Need: Reliability of 44kv supply

Scope: Install 44kv air break switch for sectionalizing circuit

Capital Costs:

Account & Description	Amount
#1835 Overhead Conductors & Devices	$19,150

Project Description: #2010 – 12 Ergonomic Project

Need: Meet current work station standards

Scope: Replacement of chairs, desk, telephone headsets

Capital Costs:

Account & Description	Amount
#1915 Furniture	$8,000

Project Description: #2010 – 13 Annual O/H and U/G Services & Upgrades

Need: System reliability

Scope: Upgrade of overhead lines and services

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$18,400
#1855 Services	$53,000
#1860 Meters	$5,500
Total	**$76,900**

Project Description: #2010 – 14 Computer Hardware

Need: Update technology

Scope: Replace PC computers

Capital Costs:

Account & Description	Amount
#1920 Computer Hardware	$6,000

Project Description: #2010 – 15 Computer Software – CIS System

Need: Update technology

Scope: CIS module upgrades to meet regulatory changes

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$5,000

Project Description: #2010 – 16 Computer Software – Other software

Need: Update technology

Scope: Replace and update engineering and operating system

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$13,700

Project Description: #2010 – 17 Tool and Equipment Replacement

Need: Equipment updating

Scope: Ongoing replacement of aging work tools and equipment

Capital Costs:

Account & Description	Amount
#1940 Tools & Equipment	$10,000

Project Description: #2010 – 18 Transportation Equipment

Need: Fleet replacement

Scope: Replacement of 20 year old RBD

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$302,000

Project Description: #2010 – 19 SCADA

Need: Technology upgrade

Scope: Upgrade of 15 year old SCADA master station

Capital Costs:

Account & Description	Amount
#1980 System Supervisory Equipment	$80,000

Project Description: #2010 – 20 Communications

Need: Mobile radio upgrade

Scope: Replacement of mobile radio and base station

Capital Costs:

Account & Description	Amount
#1985 Communications Equipment	$3,700

Forecast Capital Project Tables

Year: **2009**

Project Number	Project Description	1808 Building	1820 Distribution Stations	1830 Poles, Towers & Fixtures	1835 Overhead Conductors & Devices	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1920 Computer Hardware
2009-01	Building	6,329								
2009-02	Distribution Stations		478,615							
2009-03	New Residential Development			7,800	16,400	60,500	22,300	42,100		
2009-04	Commercial Development			2,500	10,500	13,300	62,000	1,000		
2009-05	System Expansion			10,000	39,246		2,000			
2009-06	Load Transfer Work			10,752	63,000		11,300			
2009-07	Road Relocation			21,000	4,000		2,146	17,000		
2009-08	Line Betterments			26,000	80,000		5,000			
2009-09	New Meters and Equipment								2,847	
2009-10	Transformer Betterments					3,883	15,000			
2009-11	Annual O/H and U/G Services & Upgrades							67,163		
2009-12	Computer Hardware									7,423
2009-13	Computer Software - CIS System									
2009-14	Transportation Equipment									
2009-15	SCADA									
	TOTAL	**6,329**	**478,615**	**78,052**	**213,146**	**77,683**	**119,746**	**127,263**	**2,847**	**7,423**

Forecast Capital Project Tables

Year: **2009**

Project Number	Project Description	1925 Computer Software	1930 Transportation Equipment	1980 System Supervisory Equipment	1995 Contributed Capital	TOTAL
2009-01	Building					**6,329**
2009-02	Distribution Stations					**478,615**
2009-03	New Residential Development				-119,236	**29,864**
2009-04	Commercial Development					**89,300**
2009-05	System Expansion					**51,246**
2009-06	Load Transfer Work					**85,052**
2009-07	Road Relocation					**44,146**
2009-08	Line Betterments					**111,000**
2009-09	New Meters and Equipment					**2,847**
2009-10	Transformer Betterments					**18,883**
2009-11	Annual O/H and U/G Services & Upgrades					**67,163**
2009-12	Computer Hardware					**7,423**
2009-13	Computer Software - CIS System	4,202				**4,202**
2009-14	Transportation Equipment		14,240			**14,240**
2009-15	SCADA			3,732		**3,732**
	TOTAL	**4,202**	**14,240**	**3,732**	**-119,236**	**1,014,042**

Forecast Capital Project Tables

Year: **2010**

Project Number	Project Description	1805 Land	1808 Building	1820 Distribution Stations	1830 Poles, Towers & Fixtures	1835 Overhead Conductors & Devices	1840 Underground Conduit	1845 Underground Conductors & Devices	1850 Line Transformers	1855 Services	1860 Meters	1915 Furniture	1920 Computer Hardware
2010-01	Station Grounding	24,000	6,000										
2010-02	Sub Stations Betterment			150,000									
2010-03	Annual Pole Replacement				77,100	16,000							
2010-04	New Residential Development				5,270	5,340		49,650	31,400	24,900	6,900		
2010-05	Commercial Development					12,700		12,700	54,800		11,600		
2010-06	Office Building Improvements		14,000										
2010-07	Construct Cold Storage Bldg		40,000										
2010-08	Pembroke St Rebuild (Beach.)				17,100	15,700			1,700	3,900			
2010-09	Hope Street Completion				4,000	11,600			3,120	5,400			
2010-10	Pembroke Alexander St						51,000	20,000	70,000				
2010-11	Almonte 44KV A/B					19,150							
2010-12	Ergonomic Project											8,000	
2010-13	Annual O/H and U/G Services & Upgrades								18,400	53,000	5,500		
2010-14	Computer Hardware												6,000
2010-15	Computer Software - CIS System												
2010-16	Computer Software - Other Software												
2010-17	Tool and Equipement Repla												
2010-18	Transportation Equipment												
2010-20	SCADA												
2010-19	Communications												
	TOTAL	**24,000**	**60,000**	**150,000**	**103,470**	**80,490**	**51,000**	**82,350**	**179,420**	**87,200**	**24,000**	**8,000**	**6,000**

Forecast Capital Project Tables

Year: **2010**

Project Number	Project Description	1925 Computer Software	1930 Transportation Equipment	1940 Tools & Equipment	1955 Communication Equipment	1980 System Supervisory Equipment	1995 Contributed Capital	TOTAL
2010-01	Station Grounding							**30,000**
2010-02	Sub Stations Betterment							**150,000**
2010-03	Annual Pole Replacement							**93,100**
2010-04	New Residential Development						-57,000	**66,460**
2010-05	Commercial Development						-46,000	**45,800**
2010-06	Office Building Improvements							**14,000**
2010-07	Construct Cold Storage Bldg							**40,000**
2010-08	Pembroke St Rebuild (Beach.)							**38,400**
2010-09	Hope Street Completion							**24,120**
2010-10	Pembroke Alexander St							**141,000**
2010-11	Almonte 44KV A/B							**19,150**
2010-12	Ergonomic Project							**8,000**
2010-13	Annual O/H and U/G Services & Upgrades							**76,900**
2010-14	Computer Hardware							**6,000**
2010-15	Computer Software - CIS System	5,000						**5,000**
2010-16	Computer Software - Other Software	13,700						**13,700**
2010-17	Tool and Equipement Repla			10,000				**10,000**
2010-18	Transportation Equipment		302,000					**302,000**
2010-20	SCADA					80,000		**80,000**
2010-19	Communications				3,700			**3,700**
	TOTAL	**18,700**	**302,000**	**10,000**	**3,700**	**80,000**	**-103,000**	**1,167,330**

INVESTMENT PLANNING PROCESS & STRATEGY

ORPC does not currently have a formal asset management plan in place. Asset betterment requirements are reviewed on an annual basis as part of the capital budgeting process. The size of the utility and the relatively small service area allows staff to have a good understanding of the condition of the system and the work plan required to maintain the system in reliable and safe order.

ORPC uses various tools to aid in this work: a GIS mapping system to map the entire service area, DESS software to model the system and a three year inspection of the entire system as required by the Distribution System code.

ORPC's investment planning deals primarily with renewing aging plant, largely due to surplus capacity in both distribution stations and lines caused by earlier electric heat customers switching to natural gas.

That being said, ORPC has taken a keen interest in the report prepared by KPMG as part of the OEB's review of Asset Management practices, which states: *Smaller utilities should work toward the same objectives (e.g. optimized lifecycle costing, high reliability, and high standards of safety). They may simply require less formalized processes to do so.*[1]

[1] KPMG, Review of Asset Management Practices in the Ontario Electricity Distribution Sector, March 10th, 2009, page 4

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

The working capital allowance has been derived by applying a 15% factor to projected eligible expenses, which consist of power supply expenses and controllable expenses for OM&A (Operations, Maintenance and Administration).

Attachment 1 shows the calculation of the working capital allowance by account, for the 2010 test year and preceding years since the previous Board-approved amount from the 2006 EDR.

2010 Projection vs 2009 Actual

The projected working capital allowance of $2,812K is $326K higher than the 2009 amount. The variance arises mainly from higher power supply expenses, due primarily to higher power purchases, reflecting higher volumes (following moderate weather in 2009) and higher commodity prices.

2009 Actual vs 2008 Actual

The working capital allowance of $2,486K was $63K lower than the 2008 amount. The variance arose from lower power supply expenses, mainly due to lower charges for Wholesale Market Service (combined with Rural Rate Assistance Expense) reflecting power purchased from the Brookfield generator (see Exhibit 8, Tab 3, Schedule 4).

2008 Actual vs 2007 Actual

The working capital allowance of $2,549K was $67K lower than the 2007 amount. The variance arose from lower power supply expenses, due to lower volumes and a decrease in transmission rates for network service.

2007 Actual vs 2006 Actual

The working capital allowance of $2,616K was $56K higher than the 2006 amount. The variance arose mainly from increased expenses for employee benefits (see Exhibit 4, Tab 3, Schedule 1).

2006 Actual vs 2006 Board-approved

The working capital allowance of $2,560K was $209K higher than the Board-approved amount. The variance arose mainly from higher power supply expenses, due primarily to higher commodity prices.

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection		Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	13,838,954	11,710,214		**2,128,740**	**18.2%**
	4708-Charges-WMS	451,747	834,024		**-382,277**	**(45.8%)**
	4710-Cost of Power Adjustments					
	4714-Charges-NW	953,654	838,737		**114,917**	**13.7%**
	4716-Charges-CN	449,924	672,789		**-222,865**	**(33.1%)**
	4730-Rural Rate Assistance Expense	266,941	0		**266,941**	**2669413476.1%**
	4750-Charges-LV	214,540	201,875		12,665	6.3%
	TOTAL	**16,175,760**	**14,257,639**		**1,918,122**	**13.5%**
	15% WORKING CAPITAL ALLOWANCE	***2,426,364***	***2,138,646***		***287,718***	***13.5%***
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	58,733	53,266		5,467	10.3%
	5010-Load Dispatching	50,458	40,339		10,119	25.1%
	5012-Station Buildings and Fixtures Expense	141,543	154,222		-12,679	(8.2%)
	5016-Distribution Station Equipment - Operation Labour	1,005	1,030		-25	(2.5%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	2,200			2,200	
	5020-Overhead Distribution Lines and Feeders - Operation Labour					
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,599	618		981	158.7%
	5030-Overhead Subtransmission Feeders - Operation	49			49	
	5035-Overhead Distribution Transformers- Operation	423	348		75	21.6%
	5040-Underground Distribution Lines and Feeders - Operation Labour					
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	16	144		-128	(89.1%)
	5055-Underground Distribution Transformers - Operation	73			73	
	5065-Meter Expense	53,997	51,570		2,427	4.7%
	5070-Customer Premises - Operation Labour	7,419	8,019		-600	(7.5%)
	5075-Customer Premises - Materials and Expenses	7,443	8,395		-952	(11.3%)
	5085-Miscellaneous Distribution Expense	35,519	13,047		22,472	172.2%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	7,839	7,126	713	10.0%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	24,447	26,015	-1,568	(6.0%)
	5114-Maintenance of Distribution Station Equipment	76,844	122,578	-45,734	(37.3%)
	5120-Maintenance of Poles, Towers and Fixtures	12,804	17,530	-4,726	(27.0%)
	5125-Maintenance of Overhead Conductors and Devices	291,857	181,540	**110,317**	**60.8%**
	5130-Maintenance of Overhead Services	50,130	57,158	-7,028	(12.3%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	161,222	115,275	45,947	39.9%
	5145-Maintenance of Underground Conduit		414	-414	(100.0%)
	5150-Maintenance of Underground Conductors and Devices	29,566	15,232	14,334	94.1%
	5155-Maintenance of Underground Services	21,023	11,007	10,016	91.0%
	5160-Maintenance of Line Transformers	29,677	59,452	-29,775	(50.1%)
	5175-Maintenance of Meters				
3650-Billing and Collecting	5310-Meter Reading Expense	92,805	84,614	8,191	9.7%
	5315-Customer Billing	330,619	321,239	9,380	2.9%
	5320-Collecting	153,719	147,914	5,805	3.9%
	5330-Collection Charges	-16,500	-16,357	-143	(0.9%)
	5335-Bad Debt Expense	58,000	54,806	3,194	5.8%
	5340-Miscellaneous Customer Accounts Expenses	-2,200	-2,143	-57	(2.7%)
3700-Community Relations	5410-Community Relations - Sundry	28,716	21,218	7,498	35.3%
	5415-Energy Conservation				
	5420-Community Safety Program	29,908	22,591	7,317	32.4%
	5515-Advertising Expense		50	-50	(100.0%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	40,750	38,322	2,428	6.3%
	5610-Management Salaries and Expenses	274,897	245,702	29,195	11.9%
	5615-General Administrative Salaries and Expenses	188,683	165,641	23,042	13.9%
	5620-Office Supplies and Expenses	51,070	52,399	-1,329	(2.5%)
	5630-Outside Services Employed	31,500	11,441	20,059	175.3%
	5635-Property Insurance	9,376	9,192	184	2.0%
	5645-Employee Pensions and Benefits	82,000	78,235	3,765	4.8%
	5655-Regulatory Expenses	87,000	50,591	36,409	72.0%
	5665-Miscellaneous General Expenses				
	5670-Rent	12,000	10,993	1,007	9.2%
	5675-Maintenance of General Plant	74,539	68,550	5,989	8.7%
	5680-Electrical Safety Authority Fees	8,000	7,258	742	10.2%
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	-29,915		-29,915	
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**2,570,853**	**2,316,581**	**254,272**	**11.0%**
	15% WORKING CAPITAL ALLOWANCE	***385,628***	***347,487***	***38,141***	***11.0%***
TOTAL WORKING CAPITAL ALLOWANCE		***2,811,992***	***2,486,133***	***325,859***	***13.1%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual		Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	11,710,214	11,344,648		**365,566**	**3.2%**
	4708-Charges-WMS	834,024			**834,024**	
	4710-Cost of Power Adjustments					
	4714-Charges-NW	838,737	865,502		-26,765	(3.1%)
	4716-Charges-CN	672,789	1,010,703		**-337,914**	**(33.4%)**
	4730-Rural Rate Assistance Expense	0	1,282,851		**-1,282,851**	**(100.0%)**
	4750-Charges-LV	201,875	231,572		-29,697	(12.8%)
	TOTAL	**14,257,639**	**14,735,276**		**-477,638**	**(3.2%)**
	15% WORKING CAPITAL ALLOWANCE	***2,138,646***	***2,210,291***		***-71,646***	***(3.2%)***
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	53,266	55,361		-2,095	(3.8%)
	5010-Load Dispatching	40,339	47,562		-7,223	(15.2%)
	5012-Station Buildings and Fixtures Expense	154,222	133,683		20,539	15.4%
	5016-Distribution Station Equipment - Operation Labour	1,030	947		83	8.8%
	5017-Distribution Station Equipment - Operation Supplies and Expenses		1,967		-1,967	(100.0%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour					
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	618	1,507		-889	(59.0%)
	5030-Overhead Subtransmission Feeders - Operation		46		-46	(100.0%)
	5035-Overhead Distribution Transformers-Operation	348	399		-51	(12.8%)
	5040-Underground Distribution Lines and Feeders - Operation Labour					
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	144	15		129	871.7%
	5055-Underground Distribution Transformers - Operation		69		-69	(100.0%)
	5065-Meter Expense	51,570	50,898		672	1.3%
	5070-Customer Premises - Operation Labour	8,019	6,993		1,026	14.7%
	5075-Customer Premises - Materials and Expenses	8,395	7,016		1,379	19.7%
	5085-Miscellaneous Distribution Expense	13,047	33,480		-20,433	(61.0%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	7,126	6,323	803	12.7%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	26,015	23,044	2,971	12.9%
	5114-Maintenance of Distribution Station Equipment	122,578	72,433	**50,145**	**69.2%**
	5120-Maintenance of Poles, Towers and Fixtures	17,530	12,069	5,461	45.2%
	5125-Maintenance of Overhead Conductors and Devices	181,540	184,537	-2,997	(1.6%)
	5130-Maintenance of Overhead Services	57,158	33,113	24,045	72.6%
	5135-Overhead Distribution Lines and Feeders - Right of Way	115,275	151,967	-36,692	(24.1%)
	5145-Maintenance of Underground Conduit	414		414	
	5150-Maintenance of Underground Conductors and Devices	15,232	27,869	-12,637	(45.3%)
	5155-Maintenance of Underground Services	11,007	19,816	-8,809	(44.5%)
	5160-Maintenance of Line Transformers	59,452	27,973	31,479	112.5%
	5175-Maintenance of Meters				
3650-Billing and Collecting	5310-Meter Reading Expense	84,614	107,278	-22,664	(21.1%)
	5315-Customer Billing	321,239	297,520	23,718	8.0%
	5320-Collecting	147,914	138,313	9,601	6.9%
	5330-Collection Charges	-16,357	-15,083	-1,274	(8.4%)
	5335-Bad Debt Expense	54,806	53,092	1,714	3.2%
	5340-Miscellaneous Customer Accounts Expenses	-2,143	-2,006	-137	(6.8%)
3700-Community Relations	5410-Community Relations - Sundry	21,218	34,537	-13,318	(38.6%)
	5415-Energy Conservation		8,775	-8,775	(100.0%)
	5420-Community Safety Program	22,591	28,191	-5,600	(19.9%)
	5515-Advertising Expense	50		50	

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	38,322	40,259	-1,937	(4.8%)
	5610-Management Salaries and Expenses	245,702	216,880	28,822	13.3%
	5615-General Administrative Salaries and Expenses	165,641	176,285	-10,644	(6.0%)
	5620-Office Supplies and Expenses	52,399	50,162	2,237	4.5%
	5630-Outside Services Employed	11,441	6,068	5,374	88.6%
	5635-Property Insurance	9,192	7,910	1,282	16.2%
	5645-Employee Pensions and Benefits	78,235	70,278	7,957	11.3%
	5655-Regulatory Expenses	50,591	53,748	-3,157	(5.9%)
	5665-Miscellaneous General Expenses				
	5670-Rent	10,993	11,891	-898	(7.6%)
	5675-Maintenance of General Plant	68,550	70,423	-1,873	(2.7%)
	5680-Electrical Safety Authority Fees	7,258	7,497	-239	(3.2%)
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**2,316,581**	**2,261,106**	**55,475**	**2.5%**
	15% WORKING CAPITAL ALLOWANCE	***347,487***	***339,166***	***8,321***	***2.5%***
TOTAL WORKING CAPITAL ALLOWANCE		***2,486,133***	***2,549,457***	***-63,324***	***(2.5%)***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	11,344,648	11,636,340	**-291,692**	(2.5%)
	4708-Charges-WMS				
	4710-Cost of Power Adjustments				
	4714-Charges-NW	865,502	984,533	**-119,032**	(12.1%)
	4716-Charges-CN	1,010,703	1,042,324	-31,621	(3.0%)
	4730-Rural Rate Assistance Expense	1,282,851	1,291,765	-8,914	(0.7%)
	4750-Charges-LV	231,572	202,054	29,518	14.6%
	TOTAL	**14,735,276**	**15,157,018**	**-421,741**	**(2.8%)**
	15% WORKING CAPITAL ALLOWANCE	***2,210,291***	***2,273,553***	***-63,261***	***(2.8%)***
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	55,361	46,584	8,777	18.8%
	5010-Load Dispatching	47,562	42,245	5,316	12.6%
	5012-Station Buildings and Fixtures Expense	133,683	139,025	-5,341	(3.8%)
	5016-Distribution Station Equipment - Operation Labour	947		947	
	5017-Distribution Station Equipment - Operation Supplies and Expenses	1,967		1,967	
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,507	1,972	-465	(23.6%)
	5030-Overhead Subtransmission Feeders - Operation	46		46	
	5035-Overhead Distribution Transformers- Operation	399	928	-529	(57.0%)
	5040-Underground Distribution Lines and Feeders - Operation Labour				
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	15	642	-627	(97.7%)
	5055-Underground Distribution Transformers - Operation	69	151	-82	(54.3%)
	5065-Meter Expense	50,898	41,048	9,849	24.0%
	5070-Customer Premises - Operation Labour	6,993	7,163	-170	(2.4%)
	5075-Customer Premises - Materials and Expenses	7,016	6,080	936	15.4%
	5085-Miscellaneous Distribution Expense	33,480	27,979	5,501	19.7%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,323	6,484	-161	(2.5%)
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	23,044		23,044	
	5114-Maintenance of Distribution Station Equipment	72,433	156,243	**-83,810**	(53.6%)
	5120-Maintenance of Poles, Towers and Fixtures	12,069	24,916	-12,847	(51.6%)
	5125-Maintenance of Overhead Conductors and Devices	184,537	93,027	**91,510**	98.4%
	5130-Maintenance of Overhead Services	33,113	31,184	1,929	6.2%
	5135-Overhead Distribution Lines and Feeders - Right of Way	151,967	149,907	2,060	1.4%
	5145-Maintenance of Underground Conduit		103	-103	(100.0%)
	5150-Maintenance of Underground Conductors and Devices	27,869	4,894	22,975	469.5%
	5155-Maintenance of Underground Services	19,816	2,082	17,734	851.8%
	5160-Maintenance of Line Transformers	27,973	32,269	-4,296	(13.3%)
	5175-Maintenance of Meters		742	-742	(100.0%)
3650-Billing and Collecting	5310-Meter Reading Expense	107,278	104,754	2,524	2.4%
	5315-Customer Billing	297,520	209,771	**87,749**	41.8%
	5320-Collecting	138,313	144,094	-5,781	(4.0%)
	5330-Collection Charges	-15,083	-16,433	1,350	8.2%
	5335-Bad Debt Expense	53,092	43,521	9,571	22.0%
	5340-Miscellaneous Customer Accounts Expenses	-2,006	-2,393	387	16.2%
3700-Community Relations	5410-Community Relations - Sundry	34,537	13,306	21,231	159.6%
	5415-Energy Conservation	8,775	20,507	-11,732	(57.2%)
	5420-Community Safety Program	28,191	17,482	10,709	61.3%
	5515-Advertising Expense				

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	40,259	38,268	1,991	5.2%
	5610-Management Salaries and Expenses	216,880	239,264	-22,384	(9.4%)
	5615-General Administrative Salaries and Expenses	176,285	185,023	-8,738	(4.7%)
	5620-Office Supplies and Expenses	50,162	53,408	-3,246	(6.1%)
	5630-Outside Services Employed	6,068	32,033	-25,965	(81.1%)
	5635-Property Insurance	7,910	7,268	641	8.8%
	5645-Employee Pensions and Benefits	70,278	254,428	**-184,150**	(72.4%)
	5655-Regulatory Expenses	53,748	38,134	15,613	40.9%
	5665-Miscellaneous General Expenses				
	5670-Rent	11,891		11,891	
	5675-Maintenance of General Plant	70,423	80,041	-9,618	(12.0%)
	5680-Electrical Safety Authority Fees	7,497	4,956	2,540	51.3%
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**2,261,106**	**2,283,102**	**-21,996**	**(1.0%)**
	15% WORKING CAPITAL ALLOWANCE	***339,166***	***342,465***	***-3,299***	***(1.0%)***
TOTAL WORKING CAPITAL ALLOWANCE		***2,549,457***	***2,616,018***	***-66,561***	***(2.5%)***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual		Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	11,636,340	11,557,670		**78,670**	0.7%
	4708-Charges-WMS					
	4710-Cost of Power Adjustments					
	4714-Charges-NW	984,533	1,059,200		**-74,666**	(7.0%)
	4716-Charges-CN	1,042,324	1,006,176		36,148	3.6%
	4730-Rural Rate Assistance Expense	1,291,765	1,273,299		18,467	1.5%
	4750-Charges-LV	202,054	167,108		34,946	20.9%
	TOTAL	**15,157,018**	**15,063,452**		**93,565**	**0.6%**
	15% WORKING CAPITAL ALLOWANCE	***2,273,553***	***2,259,518***		***14,035***	***0.6%***
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	46,584	56,727		-10,143	(17.9%)
	5010-Load Dispatching	42,245	39,592		2,653	6.7%
	5012-Station Buildings and Fixtures Expense	139,025	131,576		7,449	5.7%
	5016-Distribution Station Equipment - Operation Labour		335		-335	(100.0%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses					
	5020-Overhead Distribution Lines and Feeders - Operation Labour					
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,972			1,972	
	5030-Overhead Subtransmission Feeders - Operation		1,409		-1,409	(100.0%)
	5035-Overhead Distribution Transformers-Operation	928			928	
	5040-Underground Distribution Lines and Feeders - Operation Labour					
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	642			642	
	5055-Underground Distribution Transformers - Operation	151			151	
	5065-Meter Expense	41,048	53,613		-12,565	(23.4%)
	5070-Customer Premises - Operation Labour	7,163	8,915		-1,752	(19.6%)
	5075-Customer Premises - Materials and Expenses	6,080	5,958		122	2.1%
	5085-Miscellaneous Distribution Expense	27,979	20,855		7,123	34.2%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,484	6,300	183	2.9%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations		22,605	-22,605	(100.0%)
	5114-Maintenance of Distribution Station Equipment	156,243	77,505	**78,738**	101.6%
	5120-Maintenance of Poles, Towers and Fixtures	24,916	40,522	-15,607	(38.5%)
	5125-Maintenance of Overhead Conductors and Devices	93,027	116,435	-23,408	(20.1%)
	5130-Maintenance of Overhead Services	31,184	9,588	21,596	225.2%
	5135-Overhead Distribution Lines and Feeders - Right of Way	149,907	119,492	30,415	25.5%
	5145-Maintenance of Underground Conduit	103	2,927	-2,823	(96.5%)
	5150-Maintenance of Underground Conductors and Devices	4,894	26,153	-21,259	(81.3%)
	5155-Maintenance of Underground Services	2,082	5,919	-3,837	(64.8%)
	5160-Maintenance of Line Transformers	32,269	15,534	16,734	107.7%
	5175-Maintenance of Meters	742		742	
3650-Billing and Collecting	5310-Meter Reading Expense	104,754	107,617	-2,863	(2.7%)
	5315-Customer Billing	209,771	202,521	7,249	3.6%
	5320-Collecting	144,094	138,800	5,294	3.8%
	5330-Collection Charges	-16,433	-11,717	-4,716	(40.2%)
	5335-Bad Debt Expense	43,521	26,603	16,918	63.6%
	5340-Miscellaneous Customer Accounts Expenses	-2,393	-1,442	-951	(65.9%)
3700-Community Relations	5410-Community Relations - Sundry	13,306	21,507	-8,201	(38.1%)
	5415-Energy Conservation	20,507	21,061	-555	(2.6%)
	5420-Community Safety Program	17,482	21,088	-3,606	(17.1%)
	5515-Advertising Expense				

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual		Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	38,268	36,504		1,764	4.8%
	5610-Management Salaries and Expenses	239,264	246,887		-7,623	(3.1%)
	5615-General Administrative Salaries and Expenses	185,023	181,676		3,347	1.8%
	5620-Office Supplies and Expenses	53,408	69,787		-16,379	(23.5%)
	5630-Outside Services Employed	32,033	37,177		-5,145	(13.8%)
	5635-Property Insurance	7,268	7,453		-185	(2.5%)
	5645-Employee Pensions and Benefits	254,428	16,082		**238,346**	1482.0%
	5655-Regulatory Expenses	38,134	36,983		1,151	3.1%
	5665-Miscellaneous General Expenses		223		-223	(100.0%)
	5670-Rent		11,150		-11,150	(100.0%)
	5675-Maintenance of General Plant	80,041	64,052		15,989	25.0%
	5680-Electrical Safety Authority Fees	4,956	7,598		-2,641	(34.8%)
	5685-Independent Market Operator Fees and Penalties					
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes					
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**2,283,102**	**2,003,572**		**279,530**	**14.0%**
	15% WORKING CAPITAL ALLOWANCE	***342,465***	***300,536***		***41,929***	***14.0%***
TOTAL WORKING CAPITAL ALLOWANCE		***2,616,018***	***2,560,054***		***55,964***	***2.2%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved		Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	11,557,670	10,101,698		**1,455,972**	14.4%
	4708-Charges-WMS					
	4710-Cost of Power Adjustments		30,080		-30,080	(100.0%)
	4714-Charges-NW	1,059,200	1,140,056		**-80,856**	(7.1%)
	4716-Charges-CN	1,006,176	984,548		21,628	2.2%
	4730-Rural Rate Assistance Expense	1,273,299	1,268,992		4,307	0.3%
	4750-Charges-LV	167,108			**167,108**	
	TOTAL	**15,063,452**	**13,525,374**		**1,538,078**	**11.4%**
	15% WORKING CAPITAL ALLOWANCE	***2,259,518***	***2,028,806***		***230,712***	***11.4%***
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	56,727	58,407		-1,680	(2.9%)
	5010-Load Dispatching	39,592	32,872		6,720	20.4%
	5012-Station Buildings and Fixtures Expense	131,576	133,535		-1,959	(1.5%)
	5016-Distribution Station Equipment - Operation Labour	335	801		-466	(58.1%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses					
	5020-Overhead Distribution Lines and Feeders - Operation Labour		801		-801	(100.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses					
	5030-Overhead Subtransmission Feeders - Operation	1,409	801		608	75.9%
	5035-Overhead Distribution Transformers- Operation					
	5040-Underground Distribution Lines and Feeders - Operation Labour		1,601		-1,601	(100.0%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses					
	5055-Underground Distribution Transformers - Operation					
	5065-Meter Expense	53,613	80,078		-26,465	(33.0%)
	5070-Customer Premises - Operation Labour	8,915	10,511		-1,596	(15.2%)
	5075-Customer Premises - Materials and Expenses	5,958	2,203		3,755	170.4%
	5085-Miscellaneous Distribution Expense	20,855	46,803		-25,948	(55.4%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,300	5,050	1,250	24.8%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	22,605	25,267	-2,662	(10.5%)
	5114-Maintenance of Distribution Station Equipment	77,505	83,442	-5,937	(7.1%)
	5120-Maintenance of Poles, Towers and Fixtures	40,522	32,104	8,418	26.2%
	5125-Maintenance of Overhead Conductors and Devices	116,435	40,665	**75,770**	186.3%
	5130-Maintenance of Overhead Services	9,588	7,164	2,424	33.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	119,492	59,427	**60,065**	101.1%
	5145-Maintenance of Underground Conduit	2,927	3,882	-956	(24.6%)
	5150-Maintenance of Underground Conductors and Devices	26,153	2,961	23,192	783.2%
	5155-Maintenance of Underground Services	5,919	5,959	-40	(0.7%)
	5160-Maintenance of Line Transformers	15,534	32,570	-17,036	(52.3%)
	5175-Maintenance of Meters		35	-35	(100.0%)
3650-Billing and Collecting	5310-Meter Reading Expense	107,617	100,698	6,919	6.9%
	5315-Customer Billing	202,521	216,538	-14,017	(6.5%)
	5320-Collecting	138,800	119,041	19,759	16.6%
	5330-Collection Charges	-11,717	-8,009	-3,708	(46.3%)
	5335-Bad Debt Expense	26,603	28,835	-2,232	(7.7%)
	5340-Miscellaneous Customer Accounts Expenses	-1,442	2,303	-3,745	(162.6%)
3700-Community Relations	5410-Community Relations - Sundry	21,507	33,197	-11,690	(35.2%)
	5415-Energy Conservation	21,061		21,061	
	5420-Community Safety Program	21,088	17,448	3,640	20.9%
	5515-Advertising Expense		803	-803	(100.0%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	36,504	41,037	-4,533	(11.0%)
	5610-Management Salaries and Expenses	246,887	240,853	6,034	2.5%
	5615-General Administrative Salaries and Expenses	181,676	185,410	-3,734	(2.0%)
	5620-Office Supplies and Expenses	69,787	47,050	22,737	48.3%
	5630-Outside Services Employed	37,177	69,302	-32,125	(46.4%)
	5635-Property Insurance	7,453	9,821	-2,368	(24.1%)
	5645-Employee Pensions and Benefits	16,082	9,423	6,659	70.7%
	5655-Regulatory Expenses	36,983	47,825	-10,842	(22.7%)
	5665-Miscellaneous General Expenses	223	216,619	**-216,396**	(99.9%)
	5670-Rent	11,150	13,037	-1,887	(14.5%)
	5675-Maintenance of General Plant	64,052	64,904	-852	(1.3%)
	5680-Electrical Safety Authority Fees	7,598	9,123	-1,525	(16.7%)
	5685-Independent Market Operator Fees and Penalties		15,818	-15,818	(100.0%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**2,003,572**	**2,148,015**	**-144,443**	**(6.7%)**
	15% WORKING CAPITAL ALLOWANCE	***300,536***	***322,202***	***-21,666***	***(6.7%)***
TOTAL WORKING CAPITAL ALLOWANCE		***2,560,054***	***2,351,008***	***209,045***	***8.9%***

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability

SERVICE QUALITY AND RELIABILITY

ORPC reports its service quality indicators ("SQIs") annually to the Ontario Energy Board. The SQIs are defined in Chapter 7 of the Distribution System Code. OPRC has met the minimum standards for all SQIs each year, as indicated in the following table:

Table 1: Service Quality Indicators

Service Quality Indicator	Minimum Standard	2005	2006	2007	2008	2009
Connection of New Services – Low Voltage	90% or better	100	100	100	100	100
Connection of New Service – High Voltage	90% or better	n/a	n/a	n/a	n/a	n/a
Underground Cable Locates	90% or better	100	100	100	100	100
Appointments Met	90% or better	100	100	100	100	100
Telephone Accessibility	65% or better	99.7	100	99.9	99.7	99.7
Written Response to Enquires	80% or better	100	100	100	100	100
Emergency Response – Urban	80% or better	100	100	100	100	100
Emergency Response – Rural	80% or better	n/a	n/a	n/a	n/a	n/a
Reliability Metrics – excluding Loss Of Supply						
SAIDI (System Average Interruption Duration Index)	Within the range of performance over the previous 3 years		1.76	0.33	0.97	0.97
SAIFA (System Average Interruption Frequency Index)	Within the range of performance over the previous 3 years		1.36	0.39	1.20	1.20
CAIDI (Customer Average Interruption Duration Index)	Within the range of performance over the previous 3 years		1.29	0.84	0.81	0.81
Reliability Metrics – All Interruptions						
SAIDI (System Average Interruption Duration Index)			4.99	2.19	6.56	3.00
SAIFA (System Average Interruption Frequency Index)			4.37	3.00	5.77	2.87
CAIDI (Customer Average Interruption Duration Index)			1.14	0.73	1.14	1.08

Although the reliability metrics were higher in 2008, they remain in the range of performance over the previous three years. Results are used to aid in maintenance activity planning as well as asset management planning.

Exhibit 3:

REVENUE

Exhibit 3: Revenue

Tab 1 (of 3): Throughput Revenue

HISTORICAL & FORECAST VOLUMES

Attachment 1 shows the actual and forecast trends for customer/connection counts, kWh consumption and billed kW demand.

The Residential class shows stable but slow growth in customers. Historically slow growth of new residential attachments reflects the lack of new development occurring in ORPC's service area, and this is not anticipated to change in 2010.

The customer count for GS<50 kW has been declining since 2004, the decline accelerating in the most recent years. This reflects the stagnant commercial growth in ORPC's service area and movement of commercial customers to newer commercial areas that are outside the city limits of Pembroke, in particular.

The customer count for the GS>50 kW class saw an increase in 2008, due primarily to a reclassification of a number of GS<50 customers. This was a one-time event and there has been virtually no growth in 2009. No change is anticipated in 2010.

Street Lighting connections have also been stable over the period, reflecting the fact that there has not been a large amount of new development. The number of USL connections has not changed in a number of years, and Sentinel Light connections have been on a downward trend since 2005.

Utility load has been relatively stable over the historical period, with average wholesale deliveries (on an actual weather basis) increasing by less than one per cent per year from 2002 to 2008. Wholesale purchases declined by 1.9 per cent in 2009 from 2008. Wholesale purchases declined 1.0 percent in 2008 from 2007.

Historical (actual weather) Residential consumption has shown a similar pattern over the 2002 to 2008 period with an average annual growth of about 0.5 per cent. Residential consumption was down by 3.6 per cent in 2009 from 2008 and down by 1.8 per cent in 2008 from 2007.

The GS<50 kW class has seen consumption fall, consistent with declining customer numbers. Over the 2002 to 2008 period, actual consumption has declined by an average of 1.4% per year. In 2009, GS<50 kW consumption declined by 4.5% from 2008.

The GS>50 kW class has seen kWh volumes grow, on average, by approximately 1.4% per year over the 2002 to 2008 period, consistent with the historical addition of customers. However, consumption was flat in 2009. Actual use per customer in the class has declined when comparing the 2005-2009 period with the 2002-2004 period.

Street Light load has been stable and there are no changes anticipated in 2010. Sentinel Light load has been trending downwards historically due to declining customer connections. However, no changes are anticipated for 2010. The USL class consumption has tended to fluctuate from year-to-year despite no change in the number of customer connections. However, the average class consumption over 2002 to 2009 is very close to the actual class consumption in 2009. Consumption experienced in 2009 is used to forecast 2010 class consumption as well.

Volumetric Trend Table

AVERAGE CUSTOMERS (CONNECTIONS)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential	8,550	8,609	8,661	8,753	8,753	8,838	8,838	8,895
General Service Less Than 50 kW	1,487	1,457	1,446	1,424	1,424	1,402	1,402	1,391
General Service 50 to 4,999 kW	114	135	136	140	140	144	144	144
Unmetered Scattered Load		73	73	73	73	73	73	73
Sentinel Lighting	236	238	225	226	226	221	221	216
Street Lighting	2,584	2,620	2,642	2,651	2,651	2,653	2,653	2,653
TOTAL	**12,971**	**13,131**	**13,182**	**13,265**	**13,265**	**13,330**	**13,330**	**13,371**

METERED KILOWATT-HOURS (kWh)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential	78,521,656	76,867,401	80,301,785	78,894,594	80,299,772	79,327,210	76,058,961	79,547,654
General Service Less Than 50 kW	42,569,194	39,580,098	35,721,757	35,801,702	36,439,360	35,998,020	34,198,078	36,098,055
General Service 50 to 4,999 kW	82,794,551	75,435,895	78,527,667	78,693,630	80,095,228	79,125,144	78,622,636	79,345,026
Unmetered Scattered Load		364,006	348,199	386,944	386,944	437,952	437,952	437,952
Sentinel Lighting	260,779	267,504	266,011	262,124	262,124	265,370	265,370	265,370
Street Lighting	2,431,197	2,517,491	2,426,477	2,370,504	2,370,504	2,414,487	2,414,487	2,414,487
TOTAL	**206,577,377**	**195,032,395**	**197,591,896**	**196,409,498**	**199,853,932**	**197,568,183**	**191,997,484**	**198,108,544**

KILOWATTS (kW)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential								
General Service Less Than 50 kW								
General Service 50 to 4,999 kW	224,124	207,000	213,039	202,855	206,468	211,194	209,853	211,781
Unmetered Scattered Load								
Sentinel Lighting	729	767	766	751	751	760	760	760
Street Lighting	6,828	6,784	6,778	6,728	6,728	6,853	6,853	6,853
TOTAL	**231,680**	**214,551**	**220,583**	**210,334**	**213,947**	**218,807**	**217,466**	**219,394**

APPROACH TO WEATHER NORMALIZED LOAD FORECAST

Attachment 1 is the weather normalized load forecast report prepared by Elenchus Research Associates on behalf of Ottawa River Power Corporation. The forecasting approach was selected by Elenchus on the basis of historical data provided by ORPC and is described in the report.

The load forecast was developed based on monthly wholesale purchased kWh by the Distribution System from January 2002 to December 2009 as measured at the wholesale point of delivery (exclusive of losses; i.e., not loss adjusted). ORPC purchases wholesale energy from several embedded generators and also from Hydro One Networks. While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial, it is not always possible to do this due to the data limitations imposed by using class-level billing data. In the case of ORPC, class level retail consumption is available on an annual basis only. Since the utility does not perform meter readings on a calendar month basis, and only prepares an estimate of unbilled revenue at year-end, monthly retail volumes by class were not available for this forecast. Therefore, weather normalization using a statistical approach comparing monthly degree days with monthly consumption is possible only at the wholesale level. However, it is ORPC's understanding that many other LDC distribution rate applications considered by the Board have also used this approach and that this approach has been approved by the Board in the past.

The methodology predicts wholesale consumption using a multiple regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days. Historical monthly full-time employment levels are also used to account for regional economic patterns that may influence consumption of electricity within the LDC. For degree days, daily observations as reported at Ottawa (Macdonald-Cartier) International Airport are used. For employment levels, monthly full-time employment for the Kingston-Pembroke Economic Region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054773) has been used.

Neither the number of peak days nor the number of days in the month yielded meaningful results in predicting ORPC's load. Therefore, these were not included as explanatory variables.

The resulting regression equation yields an adjusted R-squared of 0.9. When actual annual wholesale values are compared to annual values predicted by the regression equation, the mean absolute percentage error (MAPE) is 1.7 per cent. More detailed model statistics can be found in the report prepared by Elenchus Research Associates (Attachment 1 to this Schedule).

Weather normalized values are determined by using the regression equation with a 10-year average monthly degree days (1999-2008). The 10-year average is consistent with recent years' weather and has been used in other electricity distribution rate applications and has been accepted by the Board.

Allocation to specific weather sensitive rate classes (Residential, GS<50, GS>50) is based on the share of each classes' actual retail kWh (exclusive of distribution losses) share of actual wholesale kWh. Weather normalized wholesale kWh is allocated to these classes based on these historical shares. Forecast values 2010 are allocated based on the most recent year's (2009) actual share.

In order to forecast 2010, an average of 4 chartered banks' economic forecasts that are available to the public on their corporate web sites is used. These forecasts include projections for employment growth in Ontario for 2009 and 2010.

Attachment 1 (of 1):

Load Forecast Report

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Ottawa River Power Corp

Updated April 30, 2010

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Ottawa River Power Corp's (ORPC) rebasing rate application for 2010 rates. A weather normal load forecast is developed for the test year (2010) and weather normalized historical consumption is also derived.

Short-term variation in monthly electricity consumption is generally influenced by weather (e.g. heating and cooling, which is by far the most dominant effect for most systems) economic activity, and timing factors, such as holidays, weekdays, and number of days in the month. We have incorporated variables, as appropriate, to account for these factors in considering ORPC's load and correcting for weather anomalies.

The forecast for ORPC is based on monthly wholesale purchased kWh by the Distribution System from January 2002 to December 2009 as measured at the wholesale point of delivery (exclusive of losses; i.e., not loss adjusted). ORPC purchases wholesale energy from several embedded generators and also from Hydro One Networks. While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial, it is not always possible to do this due to the data limitations imposed by using class-level billing data. In the case of ORPC, class level retail consumption is available on an annual basis only. Therefore, weather normalization is possible only at the wholesale level. The majority of ORPC's load is comprised of weather sensitive classes (residential, GS<50, GS>50). Therefore, we are confident that the approach taken is appropriate and yields reasonable results. We note that the OEB has approved similar approaches previously in other LDC rate rebasing proceedings.

2 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

The following table outlines monthly wholesale purchases from January 2002 to December 2009.

Table 1 - Monthly Actual Energy Purchases – ORPC

	2002	2003	2004	2005	2006	2007	2008	2009
Jan	17,765,615	20,962,476	22,662,290	23,375,223	20,121,798	19,930,522	19,648,104	21,876,886
Feb	17,036,337	21,745,026	19,706,405	19,532,450	20,144,053	20,103,742	19,442,439	20,243,845
Mar	16,930,913	17,916,204	18,012,823	18,788,975	18,617,454	18,408,483	20,142,920	17,337,917
Apr	13,959,362	17,232,531	16,764,387	16,627,361	15,813,970	16,371,659	15,178,492	15,705,676
May	15,330,983	14,989,227	15,326,962	15,334,366	14,937,402	14,545,862	14,600,277	14,476,060
Jun	14,680,285	15,583,517	14,395,229	17,387,212	15,216,019	15,445,020	15,293,284	14,635,614
Jul	16,350,315	14,993,155	15,119,204	16,573,582	17,288,815	15,701,638	15,591,426	14,252,634
Aug	15,923,517	16,243,934	15,448,245	15,704,074	14,646,590	15,347,848	16,066,893	16,099,254
Sep	14,637,457	13,973,347	15,036,229	15,074,614	14,317,893	15,532,450	14,339,118	14,079,511
Oct	15,846,977	15,549,707	14,611,343	14,827,972	16,184,185	14,439,653	15,216,339	15,646,779
Nov	17,299,091	18,211,933	18,172,545	16,770,749	16,855,953	18,194,599	17,594,470	15,885,951
Dec	19,824,120	19,574,318	22,005,795	20,488,552	19,706,059	21,797,378	20,548,340	19,609,915
Annual	**195,584,973**	**206,975,374**	**207,261,457**	**210,485,129**	**203,850,191**	**205,818,856**	**203,662,103**	**199,850,043**
% chg		***5.8%***	***0.1%***	***1.6%***	***-3.2%***	***1.0%***	***-1.0%***	***-1.9%***

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

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for the Kingston-Pembroke Economic Region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054773).

For ORPC, neither the number of peak days nor the number of days in the month yielded meaningful results.[1] Therefore, these were not included as explanatory variables.

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

Table 2
Kingston-Pembroke Full-time Employment ('000s) – CANSIM v2054773

	2002	2003	2004	2005	2006	2007	2008	2009
January	143.7	150.2	148.5	158.9	154.4	161.6	163.5	172.7
February	142.1	152.4	148.8	155.9	155.9	160.9	162.7	169.3
March	142.6	154.4	147.3	152.9	156.9	159.7	160.5	162.3
April	147.8	157.6	147.4	153.8	158.4	156.7	162.4	159.2
May	155	159.9	152.9	157	162.1	159.6	164.4	161.5
June	160.9	163.2	158.8	163.3	166.4	166.2	170.9	165
July	165.8	166	165.5	169.9	168.7	175.2	177.7	168.1
August	170	166.9	167.3	173.5	169.1	181.9	182.9	168.2
September	168.6	162.6	168.6	170.5	166.5	181.7	184.5	168.1
October	160.1	157.4	170.1	166.2	164.9	179.9	181.6	166.1
November	151.8	151.7	168.4	157.9	161.6	173.7	176.9	160.5
December	148.5	150.4	166.1	156.5	160.9	169.4	175.7	155.5
Annual Avg	**154.7**	**157.7**	**159.1**	**161.4**	**162.2**	**168.9**	**172.0**	**164.7**
Ann % chg	***3.3%***	***1.9%***	***0.9%***	***1.4%***	***0.5%***	***4.1%***	***1.8%***	***-4.2%***

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

The resulting equation, estimated using the 96 observations from 2002:01-2009:12 is displayed below:

Table 3

OLS estimates using the 96 observations 2002:01-2009:12
Dependent variable: WholesalekWh

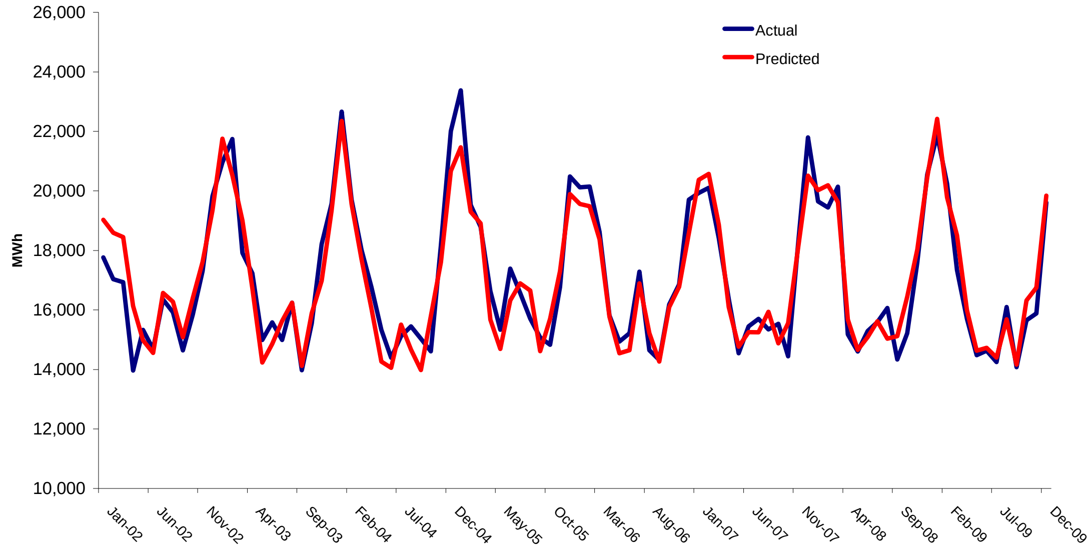
R-squared = 0.903
Adjusted R-squared = 0.900
F(3, 92) = 286.2 (P-value(F) = 1.63e-46)
Durbin-Watson = 1.637

[1] The major issue was unexplainable intuitively incorrect signs on the estimated coefficients.

Variable	*Coefficient*	*t-statistic*	*p-value*
const	8,165,885.8	5.13	<0.00001
HDD_Ott	9,479.4	26.73	<0.00001
CDD_Ott	29,600.7	10.21	<0.00001
FTE_King-Pem	28,791.5	3.03	0.00320

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

Chart 1
Ottawa River Power - Actual vs Predicted Monthly Wholesale Purchases



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.7% with the largest absolute error on an annual estimate at 3.8% for 2002.

Table 4 – Actual Deliveries vs. Estimates, ORPC

Year	*Actual wholesale kWh*	*Predicted kWh*	*Absolute % Error*
2002	195,584,973	203,021,674	3.8%
2003	206,975,374	205,314,151	0.8%
2004	207,261,457	202,202,653	2.4%
2005	210,485,129	207,412,865	1.5%
2006	203,850,191	200,225,276	1.8%
2007	205,818,856	206,130,250	0.2%
2008	203,662,103	205,962,454	1.1%
2009	199,850,043	203,218,803	1.7%
		Mean Absolute Percentage Error	***1.7%***

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes "weather normal" over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called "de Bever" method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681).

On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. We have adopted the 10 year average from 1999 to 2008 as the definition of weather normal for ORPC's weather correction analysis. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing.

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

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

Heating Degree Days	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	avg
Jan	875.4	875.3	848.2	709.4	977.3	1,045.3	920.7	733.5	797.1	754.2	**853.6**
Feb	670.9	728.2	746.8	668.8	841.5	750.0	700.6	720.9	820.0	774.3	**742.2**
Mar	645.7	502.3	652.3	651.7	675.0	559.2	668.8	600.4	643.0	721.1	**632.0**
Apr	336.8	391.0	338.1	358.8	424.6	377.8	324.8	321.6	361.1	299.6	**353.4**
May	83.3	152.0	109.6	227.6	154.1	166.2	205.0	128.2	157.3	185.4	**156.9**
Jun	20.3	63.2	25.5	61.7	38.9	54.0	16.1	27.6	34.2	22.4	**36.4**
Jul	3.8	12.2	21.6	5.3	2.0	1.8	2.9	0.3	11.8	0.3	**6.2**
Aug	14.8	18.3	4.7	6.8	13.3	29.8	8.4	18.2	20.1	14.4	**14.9**
Sep	65.8	138.1	89.9	56.9	60.4	66.8	59.2	121.0	76.0	95.4	**83.0**
Oct	321.5	290.8	266.0	370.0	336.6	287.0	269.7	335.7	227.5	321.8	**302.7**
Nov	406.7	489.4	410.1	535.2	468.8	484.3	484.2	417.3	517.0	502.8	**471.6**
Dec	691.8	882.6	602.2	728.3	722.2	814.9	762.0	610.0	787.7	762.5	**736.4**
Total	**4,136.8**	**4,543.4**	**4,115.0**	**4,380.5**	**4,714.7**	**4,637.1**	**4,422.4**	**4,034.7**	**4,452.8**	**4,454.2**	**4,389.2**

Cooling Degree Days	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	avg
Jan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Feb	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Mar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Apr	0.0	0.0	0.0	10.3	0.0	1.9	0.0	0.0	0.0	0.0	**1.2**
May	31.3	2.8	13.7	6.5	0.1	4.0	1.9	16.9	17.3	0.0	**9.5**
Jun	99.6	30.7	75.9	39.5	54.8	27.1	111.6	48.2	66.9	60.5	**61.5**
Jul	141.7	58.6	78.4	121.0	90.1	86.5	128.6	130.6	65.1	78.9	**98.0**
Aug	57.6	60.1	127.5	106.5	106.2	47.5	115.4	68.1	79.3	49.5	**81.8**
Sep	49.6	13.7	25.9	51.4	23.7	11.1	33.1	5.3	25.7	25.0	**26.5**
Oct	0.0	0.0	0.0	4.1	0.0	0.0	6.4	0.0	1.9	0.0	**1.2**
Nov	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Dec	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	**379.8**	**165.9**	**321.4**	**339.3**	**274.9**	**178.1**	**397.0**	**269.1**	**256.2**	**213.9**	**279.6**

Forecasts for Ontario's employment outlook for 2010 are available from four Canadian Chartered Banks at time of writing (2009 is now actual). Their forecasts are summarized below.

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

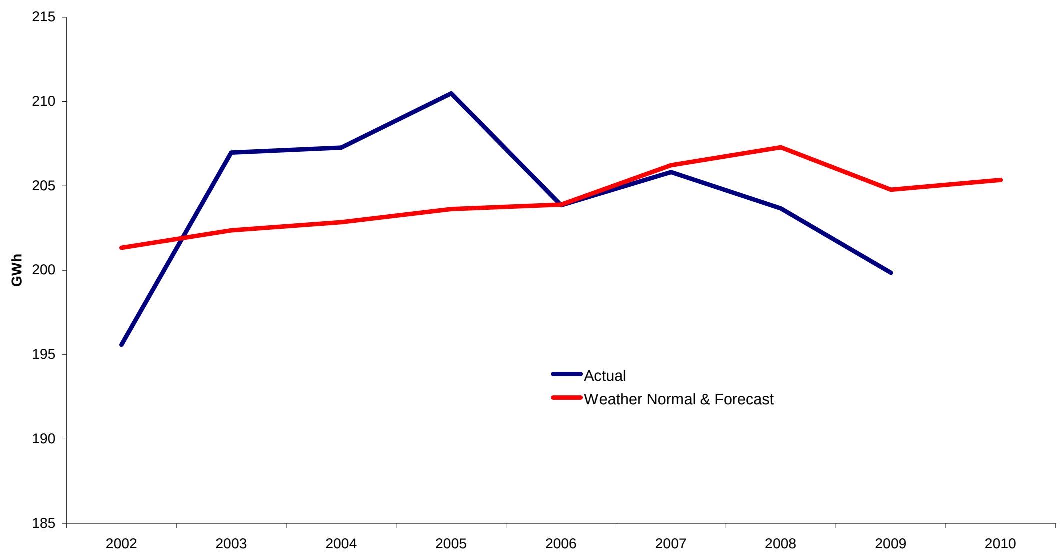
	BMO *(April 23, 2010)*	RBC *(Mar 2010)*	Scotia *(Dec. 23, 2009)*	TD *(Nov 3,2009)*	Avg
2009A	-2.4	-2.4	-2.4	-2.4	-2.4
2010F	1.1	1.3	0.7	0.8	1.0

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

Table 7 - Weather Corrected Wholesale kWh, ORPC				
			10-yr (1999-2008)	
Year	Actual wholesale kWh	%chg	Weather Normal	%chg
2002	195,584,973		201,335,420	
2003	206,975,374	*5.8%*	202,366,154	*0.5%*
2004	207,261,457	*0.1%*	202,855,609	*0.2%*
2005	210,485,129	*1.6%*	203,621,462	*0.4%*
2006	203,850,191	*-3.2%*	203,894,981	*0.1%*
2007	205,818,856	*1.0%*	206,218,451	*1.1%*
2008	203,662,103	*-1.0%*	207,289,493	*0.5%*
2009	199,850,043	*-1.9%*	204,778,878	*-1.2%*
2010F			205,347,942	*0.3%*

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

Chart 2
Ottawa River Power - Annual Actual and Weather Normal Wholesale Purchases



2.2 ALLOCATION TO SPECIFIC CLASSES

The following table (Table 8) presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2009.

Table 8 _Weather Corrected Class Specific Consumption, ORPC_			
			10-yr (1999-2008)
Year	Actual residential kWh	*Share%*[2]	Weather Normal
2002	76,563,860	39.1%	78,814,935
2003	81,096,681	39.2%	79,290,706
2004	76,429,921	36.9%	74,805,217
2005	77,582,910	36.9%	75,053,025
2006	76,867,401	37.7%	76,884,290
2007	80,301,785	39.0%	80,457,690
2008	78,894,594	38.7%	80,299,772
2009	76,058,961	38.1%	79,327,210
2010F			79,547,654
Year	Actual GS<50 kWh	*Share%*	Weather Normal
2002	39,579,801	20.2%	40,743,498
2003	43,515,459	21.0%	42,546,395
2004	44,789,581	21.6%	43,837,469
2005	43,814,909	20.8%	42,386,158
2006	39,580,098	19.4%	39,588,794
2007	35,721,757	17.4%	35,791,110
2008	35,801,702	17.6%	36,439,360
2009	34,198,078	17.1%	35,998,020
2010F			36,098,055
Year	Actual GS>50 kWh	*Share%*	Weather Normal
2002	72,549,964	37.1%	74,683,025
2003	69,539,930	33.6%	67,991,317
2004	70,049,835	33.8%	68,560,755
2005	74,429,057	35.4%	72,002,015
2006	75,435,895	37.0%	75,452,469
2007	78,527,667	38.2%	78,680,127
2008	78,693,630	38.6%	80,095,228
2009	78,622,636	39.3%	79,125,144
2010F			79,345,026

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 9 below. Historical normalized values are calculated based on the

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

annual ratio of class kW to class kWh. Forecast kW is based on the average of the class kW to class kWh ratio in 2009.

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

Year	**Actual kW**	**Class kW/kWh ratio**	**Normalized kW**
2002	188,392	0.00259672	193,931
2003	196,690	0.00282845	192,310
2004	191,625	0.00273555	187,552
2005	212,943	0.00286102	205,999
2006	207,000	0.00274405	207,045
2007	213,039	0.00271292	213,453
2008	202,855	0.00257778	206,468
2009	209,853	0.00266912	211,194
2010F			211,781

Non-Weather Sensitive Classes and Customer Connection Forecast

Table 10 below presents actual and forecast kWh and kW (where applicable) for the non-weather sensitive classes - Street Lighting, Sentinel Lighting and Unmetered Scattered Load (USL). Forecast throughput for Street Lighting, Sentinel Lighting and USL is based on the most recent actual use per customer (2009) and the forecast change in customers for these classes. No change is forecast in the number of Street Light, Sentinel Light or USL customers in 2010.

Table 10-Non Weather Sensitive Classes: ORPC

	Street Lighting				*USL*	
Year	kWh	%	kW	%	kWh	%
2002	2,345,205		6,641			
2003	2,432,181	*3.7%*	6,816	*2.6%*	448,883	
2004	2,500,576	*2.8%*	6,982	*2.4%*	496,303	*10.6%*
2005	2,426,613	*-3.0%*	6,774	*-3.0%*	593,390	*19.6%*
2006	2,517,491	*3.7%*	6,784	*0.1%*	364,006	*-38.7%*
2007	2,426,477	*-3.6%*	6,778	*-0.1%*	348,199	*-4.3%*
2008	2,370,504	*-2.3%*	6,728	*-0.7%*	386,944	*11.1%*
2009	2,414,487	*1.9%*	6,853	*1.9%*	437,952	*13.2%*
2010F	2,414,487	*0.0%*	6,853	*0.0%*	437,952	*0.0%*
	Sentinel Lighting					
2002	278,598		801			
2003	284,986	*2.3%*	848	*5.9%*		
2004	281,250	*-1.3%*	718	*-15.3%*		
2005	284,178	*1.0%*	783	*9.1%*		
2006	267,504	*-5.9%*	767	*-2.0%*		
2007	266,011	*-0.6%*	766	*-0.1%*		
2008	262,124	*-1.5%*	751	*-2.0%*		
2009	265,370	*1.2%*	760	*1.2%*		
2010F	265,370	*0.0%*	760	*0.0%*		

CUSTOMER COUNT

Residential customer additions have been modest over the 2002 – 2009 period, growing at an average rate of 0.7% per year. This is not expected to change in the forecast period. The GS<50 kW class has seen decline in both class kWh consumption and number of customers. On average, the number of GS<50 kW customers has been declining at about -0.5% per year over the 2002 – 2009 period. This is due primarily to the declining commercial base within Pembroke with many newer commercial developments taking place outside the municipal boundaries. Over the past few years, there has been an increase in the number of GS>50 kW customers. However, many of these are one-time events that are not likely to be repeated in the future (for example, new school and hospital buildings). At the same time, several large industrial customers have closed or curtailed operations, and larger commercial "big-box" type space is being located outside ORPC limits. Therefore, we do not see any potential for new GS>50 kW customer additions in 2010.

The historical annual year-end customer connections and the 2010 forecasts are displayed in Table 11 below.

Table 11 – Annual Year-End Customer Connections – ORPC

	2002	2003	2004	2005	2006	2007	2008	2009	2010F
Residential	8,439	8,501	8,550	8,593	8,625	8,696	8,809	8,866	8,923
% chg		*0.7%*	*0.6%*	*0.5%*	*0.4%*	*0.8%*	*1.3%*	*0.6%*	*0.6%*
GS<50 kW	1,443	1,464	1,467	1,461	1,453	1,438	1,409	1,394	1,387
% chg		*1.5%*	*0.2%*	*-0.4%*	*-0.5%*	*-1.0%*	*-2.0%*	*-1.1%*	*-0.5%*
GS> 50 kW	81	104	114	134	136	136	143	144	144
% chg		*28.4%*	*9.6%*	*17.5%*	*1.5%*	*0.0%*	*5.1%*	*0.7%*	*0.0%*
Street Light	2,571	2,580	2,584	2,604	2,635	2,648	2,653	2,653	2,653
% chg		*0.4%*	*0.2%*	*0.8%*	*1.2%*	*0.5%*	*0.2%*	*0.0%*	*0.0%*
Sentinel Light	286	248	236	250	225	225	226	216	216
% chg		*-13.3%*	*-4.8%*	*5.9%*	*-10.0%*	*0.0%*	*0.4%*	*-4.4%*	*0.0%*
USL					73	73	73	73	73

SUMMARY

Table 12 below presents the results for class specific historic actual and historic normalized (2008) kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 12 – ORPC Load Forecast (Historical, Bridge and Test Years).

	2008 Actual	2008 Normalized	2009 Normalized	2010f Normalized
Residential (kWh)	78,894,594	80,299,772	79,327,210	79,547,654
GS<50 (kWh)	35,801,702	36,439,360	35,998,020	36,098,055
GS>50 (kWh)	78,693,630	80,095,228	79,125,144	79,345,026
(kW)	202,855	206,468	211,194	211,781
Street Lights (kWh)	2,370,504	2,370,504	2,414,487	2,414,487
(kW)	6,728	6,728	6,853	6,853
Sentinel Lights (kWh)	262,124	262,124	265,370	265,370
(kW)	751	751	760	760
USL (kWh)	386,944	386,944	437,952	437,952
Total Retail kWh	196,409,498	199,853,932	197,568,183	198,108,544

Average Use

Displayed below (Table 13) is the observed actual average use per customer, by customer class, as well as historical weather normalized and weather normal forecast average use per customer generated using our load forecast.

Table 13 - Use Per Customer (Actual), ORPC

Year	Res	GS<50	GS>50	Street	Sent	USL
2002	9,073	27,429	895,679	912	974	
2003	9,540	29,724	668,653	943	1,149	
2004	8,939	30,531	614,472	968	1,192	
2005	9,029	29,990	555,441	932	1,137	
2006	8,912	27,240	554,676	955	1,189	4,986
2007	9,234	24,841	577,409	916	1,182	4,770
2008	8,956	25,409	550,305	894	1,160	5,301
2009	8,579	24,532	545,991	910	1,229	5,999

Weather Normal Use Per Customer

	Res	GS<50	GS>50
2002	9,339	28,235	922,013
2003	9,327	29,062	653,763
2004	8,749	29,882	601,410
2005	8,734	29,012	537,328
2006	8,914	27,246	554,798
2007	9,252	24,890	578,530

2008	9,116	25,862	560,106
2009	8,947	25,824	549,480
2010F	8,915	26,022	551,007

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Ottawa River Power Corp

Updated April 30, 2010

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Ottawa River Power Corp's (ORPC) rebasing rate application for 2010 rates. A weather normal load forecast is developed for the test year (2010) and weather normalized historical consumption is also derived.

Short-term variation in monthly electricity consumption is generally influenced by weather (e.g. heating and cooling, which is by far the most dominant effect for most systems) economic activity, and timing factors, such as holidays, weekdays, and number of days in the month. We have incorporated variables, as appropriate, to account for these factors in considering ORPC's load and correcting for weather anomalies.

The forecast for ORPC is based on monthly wholesale purchased kWh by the Distribution System from January 2002 to December 2009 as measured at the wholesale point of delivery (exclusive of losses; i.e., not loss adjusted). ORPC purchases wholesale energy from several embedded generators and also from Hydro One Networks. While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial, it is not always possible to do this due to the data limitations imposed by using class-level billing data. In the case of ORPC, class level retail consumption is available on an annual basis only. Therefore, weather normalization is possible only at the wholesale level. The majority of ORPC's load is comprised of weather sensitive classes (residential, GS<50, GS>50). Therefore, we are confident that the approach taken is appropriate and yields reasonable results. We note that the OEB has approved similar approaches previously in other LDC rate rebasing proceedings.

2 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

The following table outlines monthly wholesale purchases from January 2002 to December 2009.

Table 1 - Monthly Actual Energy Purchases – ORPC

	2002	2003	2004	2005	2006	2007	2008	2009
Jan	17,765,615	20,962,476	22,662,290	23,375,223	20,121,798	19,930,522	19,648,104	21,876,886
Feb	17,036,337	21,745,026	19,706,405	19,532,450	20,144,053	20,103,742	19,442,439	20,243,845
Mar	16,930,913	17,916,204	18,012,823	18,788,975	18,617,454	18,408,483	20,142,920	17,337,917
Apr	13,959,362	17,232,531	16,764,387	16,627,361	15,813,970	16,371,659	15,178,492	15,705,676
May	15,330,983	14,989,227	15,326,962	15,334,366	14,937,402	14,545,862	14,600,277	14,476,060
Jun	14,680,285	15,583,517	14,395,229	17,387,212	15,216,019	15,445,020	15,293,284	14,635,614
Jul	16,350,315	14,993,155	15,119,204	16,573,582	17,288,815	15,701,638	15,591,426	14,252,634
Aug	15,923,517	16,243,934	15,448,245	15,704,074	14,646,590	15,347,848	16,066,893	16,099,254
Sep	14,637,457	13,973,347	15,036,229	15,074,614	14,317,893	15,532,450	14,339,118	14,079,511
Oct	15,846,977	15,549,707	14,611,343	14,827,972	16,184,185	14,439,653	15,216,339	15,646,779
Nov	17,299,091	18,211,933	18,172,545	16,770,749	16,855,953	18,194,599	17,594,470	15,885,951
Dec	19,824,120	19,574,318	22,005,795	20,488,552	19,706,059	21,797,378	20,548,340	19,609,915
Annual	**195,584,973**	**206,975,374**	**207,261,457**	**210,485,129**	**203,850,191**	**205,818,856**	**203,662,103**	**199,850,043**
% chg		***5.8%***	***0.1%***	***1.6%***	***-3.2%***	***1.0%***	***-1.0%***	***-1.9%***

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

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for the Kingston-Pembroke Economic Region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054773).

For ORPC, neither the number of peak days nor the number of days in the month yielded meaningful results.[1] Therefore, these were not included as explanatory variables.

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

Table 2
Kingston-Pembroke Full-time Employment ('000s) – CANSIM v2054773

	2002	2003	2004	2005	2006	2007	2008	2009
January	143.7	150.2	148.5	158.9	154.4	161.6	163.5	172.7
February	142.1	152.4	148.8	155.9	155.9	160.9	162.7	169.3
March	142.6	154.4	147.3	152.9	156.9	159.7	160.5	162.3
April	147.8	157.6	147.4	153.8	158.4	156.7	162.4	159.2
May	155	159.9	152.9	157	162.1	159.6	164.4	161.5
June	160.9	163.2	158.8	163.3	166.4	166.2	170.9	165
July	165.8	166	165.5	169.9	168.7	175.2	177.7	168.1
August	170	166.9	167.3	173.5	169.1	181.9	182.9	168.2
September	168.6	162.6	168.6	170.5	166.5	181.7	184.5	168.1
October	160.1	157.4	170.1	166.2	164.9	179.9	181.6	166.1
November	151.8	151.7	168.4	157.9	161.6	173.7	176.9	160.5
December	148.5	150.4	166.1	156.5	160.9	169.4	175.7	155.5
Annual Avg	**154.7**	**157.7**	**159.1**	**161.4**	**162.2**	**168.9**	**172.0**	**164.7**
Ann % chg	***3.3%***	***1.9%***	***0.9%***	***1.4%***	***0.5%***	***4.1%***	***1.8%***	***-4.2%***

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

The resulting equation, estimated using the 96 observations from 2002:01-2009:12 is displayed below:

Table 3

OLS estimates using the 96 observations 2002:01-2009:12
Dependent variable: WholesalekWh

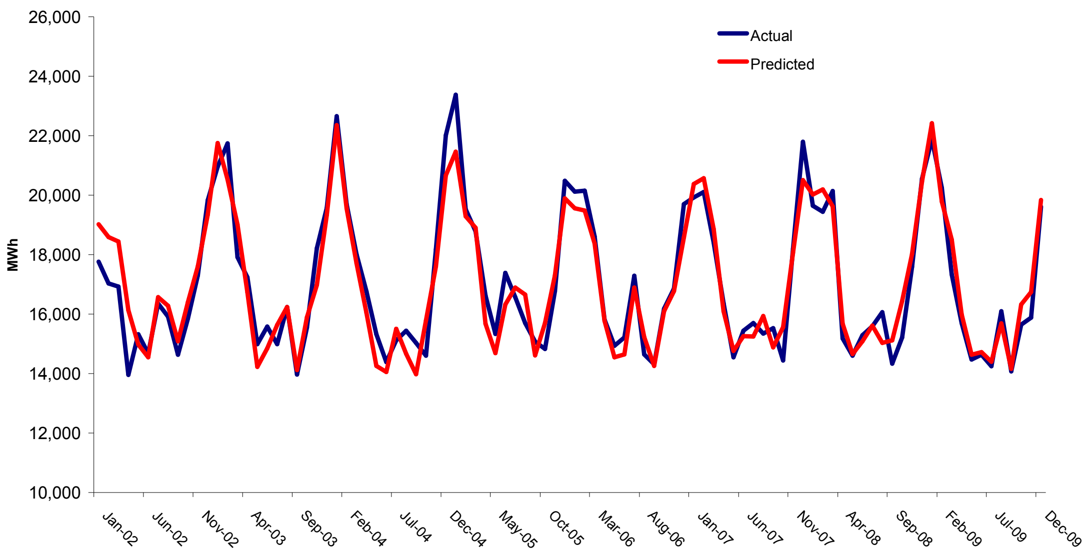
R-squared = 0.903
Adjusted R-squared = 0.900
F(3, 92) = 286.2 (P-value(F) = 1.63e-46)
Durbin-Watson = 1.637

[1] The major issue was unexplainable intuitively incorrect signs on the estimated coefficients.

Variable	*Coefficient*	*t-statistic*	*p-value*
const	8,165,885.8	5.13	<0.00001
HDD_Ott	9,479.4	26.73	<0.00001
CDD_Ott	29,600.7	10.21	<0.00001
FTE_King-Pem	28,791.5	3.03	0.00320

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

Chart 1
Ottawa River Power - Actual vs Predicted Monthly Wholesale Purchases



Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 1.7% with the largest absolute error on an annual estimate at 3.8% for 2002.

Table 4 – Actual Deliveries vs. Estimates, ORPC

Year	*Actual wholesale kWh*	*Predicted kWh*	*Absolute % Error*
2002	195,584,973	203,021,674	3.8%
2003	206,975,374	205,314,151	0.8%
2004	207,261,457	202,202,653	2.4%
2005	210,485,129	207,412,865	1.5%
2006	203,850,191	200,225,276	1.8%
2007	205,818,856	206,130,250	0.2%
2008	203,662,103	205,962,454	1.1%
2009	199,850,043	203,218,803	1.7%
		Mean Absolute Percentage Error	***1.7%***

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes “weather normal” over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called “de Bever” method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681).

On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. We have adopted the 10 year average from 1999 to 2008 as the definition of weather normal for ORPC’s weather correction analysis. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the “average” weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing.

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

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

Heating Degree Days

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	avg
Jan	875.4	875.3	848.2	709.4	977.3	1,045.3	920.7	733.5	797.1	754.2	**853.6**
Feb	670.9	728.2	746.8	668.8	841.5	750.0	700.6	720.9	820.0	774.3	**742.2**
Mar	645.7	502.3	652.3	651.7	675.0	559.2	668.8	600.4	643.0	721.1	**632.0**
Apr	336.8	391.0	338.1	358.8	424.6	377.8	324.8	321.6	361.1	299.6	**353.4**
May	83.3	152.0	109.6	227.6	154.1	166.2	205.0	128.2	157.3	185.4	**156.9**
Jun	20.3	63.2	25.5	61.7	38.9	54.0	16.1	27.6	34.2	22.4	**36.4**
Jul	3.8	12.2	21.6	5.3	2.0	1.8	2.9	0.3	11.8	0.3	**6.2**
Aug	14.8	18.3	4.7	6.8	13.3	29.8	8.4	18.2	20.1	14.4	**14.9**
Sep	65.8	138.1	89.9	56.9	60.4	66.8	59.2	121.0	76.0	95.4	**83.0**
Oct	321.5	290.8	266.0	370.0	336.6	287.0	269.7	335.7	227.5	321.8	**302.7**
Nov	406.7	489.4	410.1	535.2	468.8	484.3	484.2	417.3	517.0	502.8	**471.6**
Dec	691.8	882.6	602.2	728.3	722.2	814.9	762.0	610.0	787.7	762.5	**736.4**
Total	**4,136.8**	**4,543.4**	**4,115.0**	**4,380.5**	**4,714.7**	**4,637.1**	**4,422.4**	**4,034.7**	**4,452.8**	**4,454.2**	**4,389.2**

Cooling Degree Days

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	avg
Jan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Feb	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Mar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Apr	0.0	0.0	0.0	10.3	0.0	1.9	0.0	0.0	0.0	0.0	**1.2**
May	31.3	2.8	13.7	6.5	0.1	4.0	1.9	16.9	17.3	0.0	**9.5**
Jun	99.6	30.7	75.9	39.5	54.8	27.1	111.6	48.2	66.9	60.5	**61.5**
Jul	141.7	58.6	78.4	121.0	90.1	86.5	128.6	130.6	65.1	78.9	**98.0**
Aug	57.6	60.1	127.5	106.5	106.2	47.5	115.4	68.1	79.3	49.5	**81.8**
Sep	49.6	13.7	25.9	51.4	23.7	11.1	33.1	5.3	25.7	25.0	**26.5**
Oct	0.0	0.0	0.0	4.1	0.0	0.0	6.4	0.0	1.9	0.0	**1.2**
Nov	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Dec	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	**379.8**	**165.9**	**321.4**	**339.3**	**274.9**	**178.1**	**397.0**	**269.1**	**256.2**	**213.9**	**279.6**

Forecasts for Ontario's employment outlook for 2010 are available from four Canadian Chartered Banks at time of writing (2009 is now actual). Their forecasts are summarized below.

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

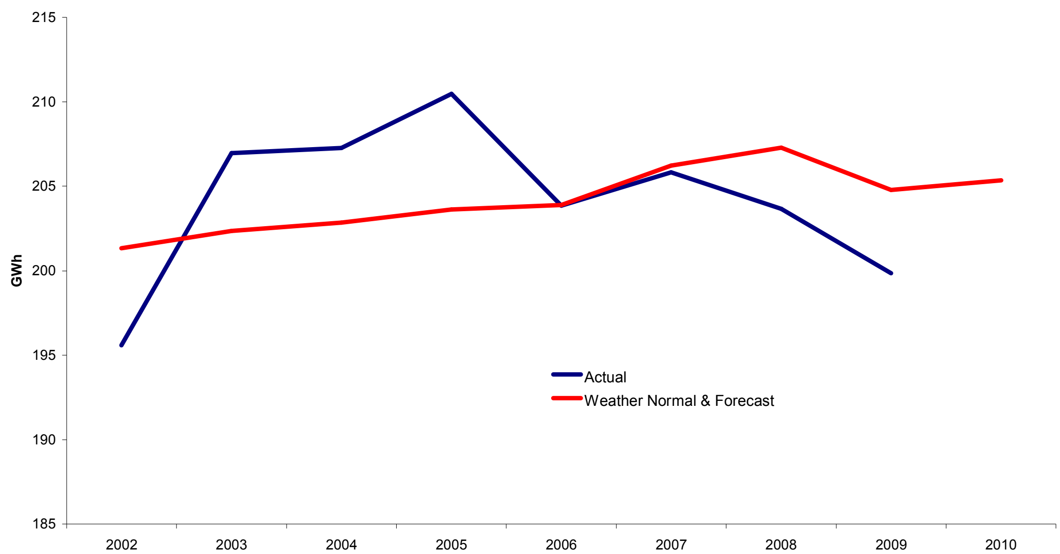
	BMO *(April 23, 2010)*	RBC *(Mar 2010)*	Scotia *(Dec. 23, 2009)*	TD *(Nov 3,2009)*	Avg
2009A	-2.4	-2.4	-2.4	-2.4	-2.4
2010F	1.1	1.3	0.7	0.8	1.0

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

Table 7 - Weather Corrected Wholesale kWh, ORPC				
			10-yr (1999-2008)	
Year	Actual wholesale kWh	%chg	Weather Normal	%chg
2002	195,584,973		201,335,420	
2003	206,975,374	*5.8%*	202,366,154	*0.5%*
2004	207,261,457	*0.1%*	202,855,609	*0.2%*
2005	210,485,129	*1.6%*	203,621,462	*0.4%*
2006	203,850,191	*-3.2%*	203,894,981	*0.1%*
2007	205,818,856	*1.0%*	206,218,451	*1.1%*
2008	203,662,103	*-1.0%*	207,289,493	*0.5%*
2009	199,850,043	*-1.9%*	204,778,878	*-1.2%*
2010F			205,347,942	*0.3%*

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

Chart 2
Ottawa River Power - Annual Actual and Weather Normal Wholesale Purchases



2.2 ALLOCATION TO SPECIFIC CLASSES

The following table (Table 8) presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2009.

Table 8 Weather Corrected Class Specific Consumption, ORPC			
			10-yr (1999-2008)
Year	Actual residential kWh	*Share%*[2]	Weather Normal
2002	76,563,860	39.1%	78,814,935
2003	81,096,681	39.2%	79,290,706
2004	76,429,921	36.9%	74,805,217
2005	77,582,910	36.9%	75,053,025
2006	76,867,401	37.7%	76,884,290
2007	80,301,785	39.0%	80,457,690
2008	78,894,594	38.7%	80,299,772
2009	76,058,961	38.1%	79,327,210
2010F			79,547,654
Year	Actual GS<50 kWh	*Share%*	Weather Normal
2002	39,579,801	20.2%	40,743,498
2003	43,515,459	21.0%	42,546,395
2004	44,789,581	21.6%	43,837,469
2005	43,814,909	20.8%	42,386,158
2006	39,580,098	19.4%	39,588,794
2007	35,721,757	17.4%	35,791,110
2008	35,801,702	17.6%	36,439,360
2009	34,198,078	17.1%	35,998,020
2010F			36,098,055
Year	Actual GS>50 kWh	*Share%*	Weather Normal
2002	72,549,964	37.1%	74,683,025
2003	69,539,930	33.6%	67,991,317
2004	70,049,835	33.8%	68,560,755
2005	74,429,057	35.4%	72,002,015
2006	75,435,895	37.0%	75,452,469
2007	78,527,667	38.2%	78,680,127
2008	78,693,630	38.6%	80,095,228
2009	78,622,636	39.3%	79,125,144
2010F			79,345,026

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 9 below. Historical normalized values are calculated based on the

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

annual ratio of class kW to class kWh. Forecast kW is based on the average of the class kW to class kWh ratio in 2009.

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

Year	Actual kW	Class kW/kWh ratio	Normalized kW
2002	188,392	0.00259672	193,931
2003	196,690	0.00282845	192,310
2004	191,625	0.00273555	187,552
2005	212,943	0.00286102	205,999
2006	207,000	0.00274405	207,045
2007	213,039	0.00271292	213,453
2008	202,855	0.00257778	206,468
2009	209,853	0.00266912	211,194
2010F			211,781

NON-WEATHER SENSITIVE CLASSES AND CUSTOMER CONNECTION FORECAST

Table 10 below presents actual and forecast kWh and kW (where applicable) for the non-weather sensitive classes - Street Lighting, Sentinel Lighting and Unmetered Scattered Load (USL). Forecast throughput for Street Lighting, Sentinel Lighting and USL is based on the most recent actual use per customer (2009) and the forecast change in customers for these classes. No change is forecast in the number of Street Light, Sentinel Light or USL customers in 2010.

Table 10-Non Weather Sensitive Classes: ORPC

	Street Lighting				*USL*	
Year	kWh	%	kW	%	kWh	%
2002	2,345,205		6,641			
2003	2,432,181	3.7%	6,816	2.6%	448,883	
2004	2,500,576	2.8%	6,982	2.4%	496,303	10.6%
2005	2,426,613	-3.0%	6,774	-3.0%	593,390	19.6%
2006	2,517,491	3.7%	6,784	0.1%	364,006	-38.7%
2007	2,426,477	-3.6%	6,778	-0.1%	348,199	-4.3%
2008	2,370,504	-2.3%	6,728	-0.7%	386,944	11.1%
2009	2,414,487	1.9%	6,853	1.9%	437,952	13.2%
2010F	2,414,487	0.0%	6,853	0.0%	437,952	0.0%
	Sentinel Lighting					
2002	278,598		801			
2003	284,986	2.3%	848	5.9%		
2004	281,250	-1.3%	718	-15.3%		
2005	284,178	1.0%	783	9.1%		
2006	267,504	-5.9%	767	-2.0%		
2007	266,011	-0.6%	766	-0.1%		
2008	262,124	-1.5%	751	-2.0%		
2009	265,370	1.2%	760	1.2%		
2010F	265,370	0.0%	760	0.0%		

Customer Count

Residential customer additions have been modest over the 2002 – 2009 period, growing at an average rate of 0.7% per year. This is not expected to change in the forecast period. The GS<50 kW class has seen decline in both class kWh consumption and number of customers. On average, the number of GS<50 kW customers has been declining at about -0.5% per year over the 2002 – 2009 period. This is due primarily to the declining commercial base within Pembroke with many newer commercial developments taking place outside the municipal boundaries. Over the past few years, there has been an increase in the number of GS>50 kW customers. However, many of these are one-time events that are not likely to be repeated in the future (for example, new school and hospital buildings). At the same time, several large industrial customers have closed or curtailed operations, and larger commercial “big-box” type space is being located outside ORPC limits. Therefore, we do not see any potential for new GS>50 kW customer additions in 2010.

The historical annual year-end customer connections and the 2010 forecasts are displayed in Table 11 below.

Table 11 – Annual Year-End Customer Connections – ORPC

	2002	2003	2004	2005	2006	2007	2008	2009	2010F
Residential	8,439	8,501	8,550	8,593	8,625	8,696	8,809	8,866	8,923
% chg		*0.7%*	*0.6%*	*0.5%*	*0.4%*	*0.8%*	*1.3%*	*0.6%*	*0.6%*
GS<50 kW	1,443	1,464	1,467	1,461	1,453	1,438	1,409	1,394	1,387
% chg		*1.5%*	*0.2%*	*-0.4%*	*-0.5%*	*-1.0%*	*-2.0%*	*-1.1%*	*-0.5%*
GS> 50 kW	81	104	114	134	136	136	143	144	144
% chg		*28.4%*	*9.6%*	*17.5%*	*1.5%*	*0.0%*	*5.1%*	*0.7%*	*0.0%*
Street Light	2,571	2,580	2,584	2,604	2,635	2,648	2,653	2,653	2,653
% chg		*0.4%*	*0.2%*	*0.8%*	*1.2%*	*0.5%*	*0.2%*	*0.0%*	*0.0%*
Sentinel Light	286	248	236	250	225	225	226	216	216
% chg		*-13.3%*	*-4.8%*	*5.9%*	*-10.0%*	*0.0%*	*0.4%*	*-4.4%*	*0.0%*
USL					73	73	73	73	73

SUMMARY

Table 12 below presents the results for class specific historic actual and historic normalized (2008) kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 12 – ORPC Load Forecast (Historical, Bridge and Test Years).

	2008 Actual	2008 Normalized	2009 Normalized	2010f Normalized
Residential (kWh)	78,894,594	80,299,772	79,327,210	79,547,654
GS<50 (kWh)	35,801,702	36,439,360	35,998,020	36,098,055
GS>50 (kWh)	78,693,630	80,095,228	79,125,144	79,345,026
(kW)	202,855	206,468	211,194	211,781
Street Lights (kWh)	2,370,504	2,370,504	2,414,487	2,414,487
(kW)	6,728	6,728	6,853	6,853
Sentinel Lights (kWh)	262,124	262,124	265,370	265,370
(kW)	751	751	760	760
USL (kWh)	386,944	386,944	437,952	437,952
Total Retail kWh	196,409,498	199,853,932	197,568,183	198,108,544

Average Use

Displayed below (Table 13) is the observed actual average use per customer, by customer class, as well as historical weather normalized and weather normal forecast average use per customer generated using our load forecast.

Table 13 - Use Per Customer (Actual), ORPC

Year	Res	GS<50	GS>50	Street	Sent	USL
2002	9,073	27,429	895,679	912	974	
2003	9,540	29,724	668,653	943	1,149	
2004	8,939	30,531	614,472	968	1,192	
2005	9,029	29,990	555,441	932	1,137	
2006	8,912	27,240	554,676	955	1,189	4,986
2007	9,234	24,841	577,409	916	1,182	4,770
2008	8,956	25,409	550,305	894	1,160	5,301
2009	8,579	24,532	545,991	910	1,229	5,999

Weather Normal Use Per Customer

	Res	GS<50	GS>50
2002	9,339	28,235	922,013
2003	9,327	29,062	653,763
2004	8,749	29,882	601,410
2005	8,734	29,012	537,328
2006	8,914	27,246	554,798
2007	9,252	24,890	578,530

2008	9,116	25,862	560,106
2009	8,947	25,824	549,480
2010F	8,915	26,022	551,007

PASS-THROUGH CHARGES

Attachment 1 shows the estimated power supply expenses for 2009 and 2010. ORPC is an embedded distributor of Hydro One Networks Inc. ("HONI") and is charged monthly by HONI for its power supply expenses. ORPC also purchases power from several embedded generators.

Pass-through charges for power supply include commodity, retail transmission services, wholesale market service, rural rate protection and low voltage service. Debt retirement charges are not included. A total loss factor applies to forecast retail volumes for all pass-through charges other than low voltage service, when the billing determinant is kWh. The calculation of total loss factors is described in Exhibit 8, Tab 3, Schedule 3.

Commodity Price

The assumed commodity prices are based on the Regulated Price Plan ("RPP") Report issued by the OEB on April 15, 2010. The estimated price for RPP customers corresponds to the average supply cost for RPP customers specified in the report's Table ES-1. For non-RPP customers, the estimated price was based on the term average of the Hourly Ontario Electricity Price ("HOEP") for the 2010 rate year (Table 1 in the report), plus the Global Adjustment (from Table ES-1).

Table 1: 2010 Commodity Price Forecasts

	$/MWh	**$/kWh**
HOEP Forecast	$36.66	$0.03666
Global Adjustment	$27.72	$0.02772
Forecast for non-RPP load	**$64.38**	**$0.06438**
Forecast for RPP load	**$69.38**	**$0.06938**

A weighted average commodity price was estimated on the basis on actual 2009 kWh's for RPP, MUSH[1] and other non-RPP customers:

[1] Municipalities, Universities, Schools and Hospital sector

Table 2: Estimated 2010 Weighted Average Commodity Price

	% share	$/kWh
MUSH	14.2%	$0.06438
RPP	60.3%	$0.06938
Non-RPP	25.5%	$0.06438
Forecast for RPP load	**100.0%**	**$0.06740**

Retail Transmission Service (“RTS”) Rates

Proposed RTS rates for Network Service and Line and Transformation Connection Service are described in Exhibit 8, Tab 3, Schedule 1.

Wholesale Market Service (“WMS”) Rate

ORPC proposes to reduce the WMS rate charged to customers from $0.0052 to $0.0022 per kWh, as described in Exhibit 8, Tab 3, Schedule 4.

Rural Rate Protection

The existing Rural Rate Protection charge of $0.0013 per kWh has been maintained.

Low Voltage (“LV”) Service

ORPC estimates total charges of $214,540 in 2010 for LV service. Proposed retail rates for LV are described in Exhibit 8, Tab 3, Schedule 2.

Projected Power Supply Expenses

Electricity (Commodity)	Customer Class Name	2009 Volume	rate ($/kWh):	$0.06740 Amount
kWh	Residential	78,835,113		5,313,130
kWh	General Service Less Than 50 kW	35,446,308		2,388,921
kWh	General Service 50 to 4,999 kW	81,492,362		5,492,217
kWh	Unmetered Scattered Load	453,937		30,593
kWh	Sentinel Lighting	275,056		18,538
kWh	Street Lighting	2,502,616		168,665
	TOTAL	**199,005,392**		**13,412,064**

Transmission - Network	Customer Class Name	2009 Volume	Rate	Amount
kWh	Residential	78,835,113	$0.0045	354,758
kWh	General Service Less Than 50 kW	35,446,308	$0.0041	145,330
kW	General Service 50 to 4,999 kW	209,853	$1.6741	351,315
kWh	Unmetered Scattered Load	453,937	$0.0041	1,861
kW	Sentinel Lighting	760	$1.2689	964
kW	Street Lighting	6,853	$1.2624	8,651
	TOTAL	**114,952,824**		**862,880**

Transmission - Connection	Customer Class Name	2009 Volume	Rate	Amount
kWh	Residential	78,835,113	$0.0053	417,826
kWh	General Service Less Than 50 kW	35,446,308	$0.0048	170,142
kW	General Service 50 to 4,999 kW	209,853	$1.8886	396,328
kWh	Unmetered Scattered Load	453,937	$0.0048	2,179
kW	Sentinel Lighting	760	$1.4906	1,133
kW	Street Lighting	6,853	$1.4600	10,005
	TOTAL	**114,952,824**		**997,614**

Projected Power Supply Expenses

Wholesale Market Service		**Customer**	**2009**	*rate ($/kWh):*	**$0.00520**
		Class Name	**Volume**		**Amount**
	kWh	Residential	78,835,113		409,943
	kWh	General Service Less Than 50 kW	35,446,308		184,321
	kWh	General Service 50 to 4,999 kW	81,492,362		423,760
	kWh	Unmetered Scattered Load	453,937		2,360
	kWh	Sentinel Lighting	275,056		1,430
	kWh	Street Lighting	2,502,616		13,014
		TOTAL	**199,005,392**		**1,034,828**
Rural Rate Protection		**Customer**	**2009**	*rate ($/kWh):*	**$0.00130**
		Class Name	**Volume**		**Amount**
	kWh	Residential	76,058,961		98,877
	kWh	General Service Less Than 50 kW	34,198,078		44,458
	kWh	General Service 50 to 4,999 kW	78,622,636		102,209
	kWh	Unmetered Scattered Load	437,952		569
	kWh	Sentinel Lighting	265,370		345
	kWh	Street Lighting	2,414,487		3,139
		TOTAL	**191,997,484**		**249,597**
Debt Retirement Charge		**Customer**	**2009**	*rate ($/kWh):*	**$0.00490**
		Class Name	**Volume**		**Amount**
		TOTAL			
Low Voltage Charges		**Customer**		**2009**	
		Class Name	**Volume**		**Amount**
		TOTAL (Input amount)		201,875	**201,875**
GRAND TOTAL					**16,758,857**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	Customer Class Name	2010 Volume	rate ($/kWh):	$0.06740 Amount
kWh	Residential	82,451,143		5,556,834
kWh	General Service Less Than 50 kW	37,415,634		2,521,645
kWh	General Service 50 to 4,999 kW	82,241,119		5,542,680
kWh	Unmetered Scattered Load	453,937		30,593
kWh	Sentinel Lighting	275,056		18,538
kWh	Street Lighting	2,502,616		168,665
	TOTAL	**205,339,506**		**13,838,954**

Transmission - Network	Customer Class Name	2010 Volume	Rate	Amount
kWh	Residential	82,451,143	$0.0048	395,765
kWh	General Service Less Than 50 kW	37,415,634	$0.0044	164,629
kW	General Service 50 to 4,999 kW	211,781	$1.7987	380,930
kWh	Unmetered Scattered Load	453,937	$0.0044	1,997
kW	Sentinel Lighting	760	$1.3633	1,036
kW	Street Lighting	6,853	$1.3564	9,295
	TOTAL	**120,540,109**		**953,654**

Transmission - Connection	Customer Class Name	2010 Volume	Rate	Amount
kWh	Residential	82,451,143	$0.0023	189,638
kWh	General Service Less Than 50 kW	37,415,634	$0.0021	78,573
kW	General Service 50 to 4,999 kW	211,781	$0.8304	175,863
kWh	Unmetered Scattered Load	453,937	$0.0021	953
kW	Sentinel Lighting	760	$0.6554	498
kW	Street Lighting	6,853	$0.6420	4,400
	TOTAL	**120,540,109**		**449,924**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

		Customer	2010	rate ($/kWh):	$0.00220
Wholesale Market Service		**Class Name**	**Volume**		**Amount**
	kWh	Residential	82,451,143		181,393
	kWh	General Service Less Than 50 kW	37,415,634		82,314
	kWh	General Service 50 to 4,999 kW	82,241,119		180,930
	kWh	Unmetered Scattered Load	453,937		999
	kWh	Sentinel Lighting	275,056		605
	kWh	Street Lighting	2,502,616		5,506
		TOTAL	**205,339,506**		**451,747**
Rural Rate Protection		**Customer**	**2010**	rate ($/kWh):	**$0.00130**
		Class Name	**Volume**		**Amount**
	kWh	Residential	82,451,143		107,186
	kWh	General Service Less Than 50 kW	37,415,634		48,640
	kWh	General Service 50 to 4,999 kW	82,241,119		106,913
	kWh	Unmetered Scattered Load	453,937		590
	kWh	Sentinel Lighting	275,056		358
	kWh	Street Lighting	2,502,616		3,253
		TOTAL	**205,339,506**		**266,941**
Debt Retirement Charge		**Customer**	**2010**	rate ($/kWh):	**$0.00490**
		Class Name	**Volume**		**Amount**
		TOTAL			
Low Voltage Charges		**Customer**		**2010**	
		Class Name	**Volume**		**Amount**
		TOTAL (Input amount)		214,540	**214,540**
GRAND TOTAL					**16,175,760**

Exhibit 3: Revenue

Tab 2 (of 3): Distribution Revenue

OVERVIEW OF DISTRIBUTION REVENUE

Attachment 1 shows estimated revenues from current distribution charges for 2009 and 2010.

Distribution revenue is derived through a combination of fixed monthly charges and volumetric charges based either on consumption (kWh's) or demand (kW's). Revenues are collected from 6 customer classes: Residential, General Service less than 50 kW, General Service greater than 50 kW, Unmetered Scattered Load (USL), Sentinel Lighting and Street Lighting

Fixed rate revenue is determined by applying the current fixed monthly charge to the number of customers or connections in each of the customer classes in each month. Variable rate revenue is based on a volumetric rate applied to meter readings for consumption or demand volume.

Existing volumetric rates include an embedded rate adder for Low Voltage service, and may also include a component to recover allowances for transformer ownership. These amounts have been deducted in order to arrive at net distribution revenue by customer class.

Pro-forma Revenue from Current Distribution Charges

LOW VOLTAGE CHARGES		2009			2010 at Existing Rates		
		Rate	**Volume ***	**Revenue**	**Rate**	**Volume ***	**Revenue**
Residential	kWh	$0.0011	76,058,961	83,665	$0.0011	79,547,654	87,502
General Service Less Than 50 kW	kWh	$0.0011	34,198,078	37,618	$0.0011	36,098,055	39,708
General Service 50 to 4,999 kW	kW	$0.3526	209,853	73,994	$0.3526	211,781	74,674
Unmetered Scattered Load	kWh	$0.0011	437,952	482	$0.0011	437,952	482
Sentinel Lighting	kW	$0.3207	760	244	$0.3207	760	244
Street Lighting	kW	$0.3260	6,853	2,234	$0.3260	6,853	2,234
TOTAL				**198,236**			**204,844**

TRANSFORMER ALLOWANCES		2009			2010 at Existing Rates		
		Rate **	**Volume**	**Amount**	**Rate ****	**Volume**	**Amount**
Residential							
General Service Less Than 50 kW							
General Service 50 to 4,999 kW	kW	($0.6000)	51,302	-30,781	($0.6000)	50,590	-30,354
Unmetered Scattered Load							
Sentinel Lighting	kW	($0.6000)			($0.6000)		
Street Lighting	kW	($0.6000)			($0.6000)		
TOTAL			**51,302**	**-30,781**		**50,590**	**-30,354**

** per sheet C1*
*** per sheet C3*

Pro-forma Revenue from Current Distribution Charges

2009 Distribution Revenue by Class	Gross Distr. Revenue [1]	LV Charges	Transformer Allowances	Net Distr. Revenue
Residential	2,081,561	-83,665		1,997,896
General Service Less Than 50 kW	660,735	-37,618		623,118
General Service 50 to 4,999 kW	902,861	-73,994	-30,781	798,086
Unmetered Scattered Load	23,266	-482		22,784
Sentinel Lighting	6,883	-244		6,639
Street Lighting	46,558	-2,234		44,324
TOTAL	**3,721,864**	**-198,236**	**-30,781**	**3,492,847**

2010 Distribution Revenue by Class	Gross Distr. Revenue [1]	LV Charges	Transformer Allowances	Net Distr. Revenue
Residential	2,131,264	-87,502		2,043,761
General Service Less Than 50 kW	673,547	-39,708		633,839
General Service 50 to 4,999 kW	908,501	-74,674	-30,354	803,473
Unmetered Scattered Load	23,266	-482		22,784
Sentinel Lighting	6,802	-244		6,559
Street Lighting	46,558	-2,234		44,324
TOTAL	**3,789,939**	**-204,844**	**-30,354**	**3,554,741**

[1] *per sheet C4*

Pro-forma Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	2009 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$10.9500	8,838	1,161,248	$0.0121	kWh	76,058,961	920,313	2,081,561
General Service Less Than 50 kW	$22.4100	1,402	376,891	$0.0083	kWh	34,198,078	283,844	660,735
General Service 50 to 4,999 kW	$270.2800	144	465,422	$2.0845	kW	209,853	437,439	902,861
Unmetered Scattered Load	$22.4100	73	19,631	$0.0083	kWh	437,952	3,635	23,266
Sentinel Lighting	$1.3400	221	3,554	$4.3804	kW	760	3,329	6,883
Street Lighting	$0.8300	2,653	26,424	$2.9380	kW	6,853	20,134	46,558
Gross Revenue (before Transformer Allowances)			2,053,170				1,668,694	3,721,864
Transformer Allowances				($0.6000)	kW	51,302	-30,781	-30,781
Total Revenue			**2,053,170**				**1,637,913**	**3,691,083**
Less: Pass-through amount embedded in distribution rates *							-198,236	-198,236
DISTRIBUTION REVENUE			**2,053,170**				**1,439,677**	**3,492,847**

Customer Class Name	2010 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$10.9500	8,895	1,168,737	$0.0121	kWh	79,547,654	962,527	2,131,264
General Service Less Than 50 kW	$22.4100	1,391	373,933	$0.0083	kWh	36,098,055	299,614	673,547
General Service 50 to 4,999 kW	$270.2800	144	467,044	$2.0845	kW	211,781	441,457	908,501
Unmetered Scattered Load	$22.4100	73	19,631	$0.0083	kWh	437,952	3,635	23,266
Sentinel Lighting	$1.3400	216	3,473	$4.3804	kW	760	3,329	6,802
Street Lighting	$0.8300	2,653	26,424	$2.9380	kW	6,853	20,134	46,558
Gross Revenue (before Transformer Allowances)			2,059,243				1,730,696	3,789,939
Transformer Allowances				($0.6000)	kW	50,590	-30,354	-30,354
Total Revenue			**2,059,243**				**1,700,342**	**3,759,585**
Less: Pass-through amount embedded in distribution rates *							-204,844	-204,844
DISTRIBUTION REVENUE			**2,059,243**				**1,495,498**	**3,554,741**

** per revenue amounts on sheet C2 e.g. Low Voltage*

Exhibit 3: Revenue

Tab 3 (of 3): Other Revenue

OVERVIEW OF OTHER REVENUE

Attachment 1 shows the trend of Other Revenue by USA account, which includes Specific Service Charges, Late Payment Charges, Other Distribution Revenues and Other Income & Expenses. For the latter two categories, further breakdowns are provided in Attachment 2.

Other Revenue has grown over the 2006 to 2009 period but is forecast to decline substantially in 2010, due primarily to lower interest income and jobbing revenues.

Schedule 2 provides additional details on projected service charges. Schedule 3 describes the significant variances in other revenues. Schedule 4 presents the revenue offsets which are applied to the base revenue requirement for the 2010 test year.

Other Revenue Trend Table

Account	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009	2010
4080-SSS Admin Charge		29,327	27,783	27,802	27,515	27,515
4082-Retail Services Revenues	1,890	9,078	11,223	14,073	15,101	15,105
4084-Service Transaction Requests (STR) Revenues	11	1,079	550	457	20	23
4090-Electric Services Incidental to Energy Sales *	30,317					
4210-Rent from Electric Property		49,230	39,881	40,534	41,996	42,000
4225-Late Payment Charges	23,883	25,610	30,603	27,322	45,304	45,000
4230-Sales of Water and Water Power	18,892					
4235-Miscellaneous Service Revenues	34,410	39,135	49,140	43,851	46,740	47,325
4325-Revenues from Merchandise, Jobbing, Etc.	54,009	45,180	47,034	83,827	114,407	70,000
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-11,681					
4355-Gain on Disposition of Utility and Other Property				13,375		12,000
4390-Miscellaneous Non-Operating Income	1,844	9,681	6,019	9,277	17,388	15,000
4405-Interest and Dividend Income	101,282	125,666	174,670	148,561	186,944	88,820
Specific Service Charges	34,410	39,135	49,140	43,851	46,740	47,325
Late Payment Charges	23,883	25,610	30,603	27,322	45,304	45,000
Other Distribution Revenues	51,110	88,714	79,437	82,865	84,632	84,643
Other Income and Expenses	145,454	180,528	227,723	255,040	318,739	185,820
TOTAL	254,857	333,986	386,903	409,078	495,415	362,788

** 2006 EDR Approved corresponds to SSS Admin Charge amount*

Specific Service Charges:	Account 4235
Late Payment Charges:	Account 4225
Other Distribution Revenues:	Accounts 4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	Accounts 4305, 4315, 4320, 4325, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Other Revenue Account Breakdowns

Account	Description
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4210	Rent from Electric Property
4325	Revenues from Merchandise, Jobbing, Etc.
4355	Gain on Disposition of Utility and Other Property
4390	Miscellaneous Non-Operating Income
4405	Interest and Dividend Income

Other Revenue Account Breakdowns

Account: 4082
Retail Services Revenues

	Actual			Bridge	Test
	2006	2007	2008	2009	2010
Retailer Service Agreements	6,897	7,952	10,042	10,625	10,605
Distributor-Consolidated Billing	2,181	3,272	4,004	4,477	4,500
Other	0	0	27	0	0
4082-Retail Services Revenues	**9,078**	**11,223**	**14,073**	**15,101**	**15,105**

Other Revenue Account Breakdowns

Account: 4084
Service Transaction Requests (STR) Revenues

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Request Fees	863	330	274	12	13
Processing Fees	216	220	183	8	10
Other	0	0	0	0	0
4084-Service Transaction Requests (STR) Revenues	**1,079**	**550**	**457**	**20**	**23**

Other Revenue Account Breakdowns

Account: 4210
Rent from Electric Property

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Access to Power Poles	49,230	39,881	40,534	41,996	42,000
Other	-0	-0	0	0	0
4210-Rent from Electric Property	**49,230**	**39,881**	**40,534**	**41,996**	**42,000**

Other Revenue Account Breakdowns

Account: 4325
Revenues from Merchandise, Jobbing, Etc.

	Actual			Bridge	Test
	2006	2007	2008	2009	2010
Misc jobs - plant shut downs, accidents etc.	45,180	47,034	83,827	114,407	70,000
Other	0	0	0	0	0
4325-Revenues from Merchandise, Jobbing, Etc.	**45,180**	**47,034**	**83,827**	**114,407**	**70,000**

Other Revenue Account Breakdowns

Account: 4355
Gain on Disposition of Utility and Other Property

	Actual			Bridge	Test
	2006	2007	2008	2009	2010
Gain on sale of vehicle			13,375		12,000
Other	0	0	0	0	0
4355-Gain on Disposition of Utility and Other Property	**0**	**0**	**13,375**	**0**	**12,000**

Other Revenue Account Breakdowns

Account: ***4390***
Miscellaneous Non-Operating Income

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Sale of scrap	9,681	6,019	9,277	17,388	15,000
Other	0	0	0	0	0
4390-Miscellaneous Non-Operating Income	**9,681**	**6,019**	**9,277**	**17,388**	**15,000**

Other Revenue Account Breakdowns

Account:* *4405
Interest and Dividend Income

	Actual			Bridge	Test
	2006	2007	2008	2009	2010
Interest on bank deposits and investments	243,796	281,013	261,834	167,912	110,000
Interest income on deferral/variance accounts	-118,130	-106,344	-113,272	19,032	-16,445
Other	0	0	-0	0	3
4405-Interest and Dividend Income	**125,666**	**174,670**	**148,561**	**186,944**	**93,558**

REVENUE FROM SERVICE CHARGES

Attachment 1 shows the revenue realized from services charges for the 2006 Board-approved amount, 2006 to 2009 actuals, and the projection for 2010.

No changes to any existing rates for specific service charges are proposed in this application.

Trend Table of Revenue from Service Charges

Service	USA #	2006 EDR Approved			2006 Actual		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	121,268	$0.25	30,317	117,310	$0.25	29,327
Arrears Certificate	4084	174	$15.00	2,610		$15.00	
Account history	4235	49	$15.00	735	34	$15.00	515
Returned Cheque charge (plus bank charges)	5330	349	$15.00	5,235	173	$15.00	2,598
Legal letter charge	5340				154	$15.00	2,310
Account set up charge / change of occupancy charge	4235	1,581	$30.00	47,440	1,287	$30.00	38,620
Late Payment - per month	4225	1,592,200	1.50%	23,883	1,707,311	1.50%	25,610
Collection of account charge – no disconnection	5330	227	$30.00	6,800	135	$30.00	4,058
Disconnect/Reconnect at meter – during regular hours	5330	137	$65.00	8,905	75	$65.00	4,890
Disconnect/Reconnect at meter – after regular hours	4235	16	$185.00	2,899	1	$185.00	185
Retailer Service Agreement -- standard charge	4082	3	$100.00	300	2	$100.00	200
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	61	$20.00	1,220	108	$20.00	2,160
Retailer Service Agreement -- monthly variable charge (per customer)	4082	498	$0.50	249	9,073	$0.50	4,537
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	429	$0.30	129	7,271	$0.30	2,181
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	26	($0.30)	-8		($0.30)	
Service Transaction Request -- request fee (per request)	4084	27	$0.25	7	3,453	$0.25	863
Service Transaction Request -- processing fee (per processed request)	4084	8	$0.50	4	431	$0.50	216
TOTAL				**130,724**			**118,270**

Trend Table of Revenue from Service Charges

		2007 Actual			2008 Actual		
Service	**USA #**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**
Standard Supply Service -- Administrative Charge	4080	111,133	$0.25	27,783	111,207	$0.25	27,802
Arrears Certificate	4084		$15.00			$15.00	
Account history	4235	40	$15.00	600	60	$15.00	906
Returned Cheque charge (plus bank charges)	5330	187	$15.00	2,805	177	$15.00	2,655
Legal letter charge	5340	172	$15.00	2,581	156	$15.00	2,340
Account set up charge / change of occupancy charge	4235	1,618	$30.00	48,540	1,432	$30.00	42,945
Late Payment - per month	4225	2,040,213	1.50%	30,603	1,821,463	1.50%	27,322
Collection of account charge – no disconnection	5330	248	$30.00	7,440	233	$30.00	6,990
Disconnect/Reconnect at meter – during regular hours	5330	79	$65.00	5,135	76	$65.00	4,940
Disconnect/Reconnect at meter – after regular hours	4235	5	$185.00	925	2	$185.00	370
Retailer Service Agreement -- standard charge	4082	3	$100.00	300	2	$100.00	200
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	99	$20.00	1,980	143	$20.00	2,860
Retailer Service Agreement -- monthly variable charge (per customer)	4082	11,343	$0.50	5,672	13,964	$0.50	6,982
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	10,905	$0.30	3,272	13,345	$0.30	4,004
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,319	$0.25	330	1,096	$0.25	274
Service Transaction Request -- processing fee (per processed request)	4084	440	$0.50	220	365	$0.50	183
TOTAL				**138,185**			**130,772**

Trend Table of Revenue from Service Charges

Service	USA #	2009 Projection			2010 Projection (existing rates)		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	110,061	$0.25	27,515	110,061	$0.25	27,515
Arrears Certificate	4084		$15.00			$15.00	
Account history	4235	54	$15.00	810	55	$15.00	825
Returned Cheque charge (plus bank charges)	5330	181	$15.00	2,715	180	$15.00	2,700
Legal letter charge	5340	157	$15.00	2,355	157	$15.00	2,355
Account set up charge / change of occupancy charge	4235	1,531	$30.00	45,930	1,550	$30.00	46,500
Late Payment - per month	4225	3,020,274	1.50%	45,304	3,000,000	1.50%	45,000
Collection of account charge – no disconnection	5330	298	$30.00	8,940	300	$30.00	9,000
Disconnect/Reconnect at meter – during regular hours	5330	71	$65.00	4,630	71	$65.00	4,630
Disconnect/Reconnect at meter – after regular hours	4235		$185.00			$185.00	
Retailer Service Agreement -- standard charge	4082	1	$100.00	100	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	145	$20.00	2,900	144	$20.00	2,880
Retailer Service Agreement -- monthly variable charge (per customer)	4082	15,249	$0.50	7,625	15,250	$0.50	7,625
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	14,922	$0.30	4,477	15,000	$0.30	4,500
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	47	$0.25	12	50	$0.25	13
Service Transaction Request -- processing fee (per processed request)	4084	16	$0.50	8	20	$0.50	10
TOTAL				**153,320**			**153,653**

Trend Table of Revenue from Service Charges

USA Account #s per sheet Y6

Service	USA #	2010 Projection (proposed rates)		
		Volume	**Rate**	**Revenue**
Standard Supply Service -- Administrative Charge	4080	110,061	$0.25	27,515
Arrears Certificate	4084		$15.00	
Account history	4235	55	$15.00	825
Returned Cheque charge (plus bank charges)	5330	180	$15.00	2,700
Legal letter charge	5340	157	$15.00	2,355
Account set up charge / change of occupancy charge	4235	1,550	$30.00	46,500
Late Payment - per month	4225	3,000,000	1.50%	45,000
Collection of account charge – no disconnection	5330	300	$30.00	9,000
Disconnect/Reconnect at meter – during regular hours	5330	71	$65.00	4,630
Disconnect/Reconnect at meter – after regular hours	4235		$185.00	
Retailer Service Agreement -- standard charge	4082	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	144	$20.00	2,880
Retailer Service Agreement -- monthly variable charge (per customer)	4082	15,250	$0.50	7,625
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	15,000	$0.30	4,500
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)	
Service Transaction Request -- request fee (per request)	4084	50	$0.25	13
Service Transaction Request -- processing fee (per processed request)	4084	20	$0.50	10
TOTAL				**153,653**

OTHER REVENUE VARIANCE ANALYSIS

Attachment 1 shows the annual variances in other revenue.

2010 Test Year vs 2009 Bridge Year

Other revenue in 2010 is projected to be $133K lower than in 2009. $98K of the variance arises from lower interest income, reflecting lower interest rates, a lower cash balance, and the fact that the 2010 projection is net of interest expense on credit balances in deferral & variance accounts. The remainder of the variance is primarily due to lower revenues from jobbing, which were exceptionally high in 2009 (see below).

2009 Bridge Year vs 2008 Actual

Other revenue in 2009 was $86K higher than in 2008. $38K of the variance arose from higher interest income, reflecting higher interest income on deferral and variance balances. The remainder of the variance was primarily due to higher revenues from jobbing and an increase in late payment charges. Revenues from jobbing were exceptionally high in both 2008 and 2009, as a result of work performed for Ottawa River Energy Solutions (an affiliate of ORPC), which was heavily involved in a project to extend fibre to a number of customers as part of the Government of Ontario’s e-Health initiative.

2008 Actual vs 2007 Actual

Other revenue in 2008 was $22K higher than in 2007. The variance, principally due to higher revenues from jobbing (see above), was less than the materiality threshold.

2007 Actual vs 2006 Actual

Other revenue in 2007 was $49K greater than in 2006. The variance was mainly due to increased interest income, arising from higher interest rates and a higher cash balance.

2006 Actual vs 2006 Board-Approved

Other revenue in 2006 was $79K greater than the Board-approved amount. $49K of the variance was due to rental revenue for access to power poles, which were not included in the Board-approved amount. The remainder of the variance arose mainly from higher interest income.

Other Revenue Variances Table

Account Grouping	Account Description	2010	2009	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-27,515	-27,515		
	4082-Retail Services Revenues	-15,105	-15,101	-4	(0.0%)
	4084-Service Transaction Requests (STR) Revenues	-23	-20	-3	(13.9%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-42,000	-41,996	-4	(0.0%)
	4225-Late Payment Charges	-45,000	-45,304	304	0.7%
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-47,325	-46,740	-585	(1.3%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-70,000	-114,407	44,407	38.8%
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property	-12,000		-12,000	
	4390-Miscellaneous Non-Operating Income	-15,000	-17,388	2,388	13.7%
3200-Investment Income	4405-Interest and Dividend Income	-88,820	-186,944	**98,124**	**52.5%**

Other Revenue Variances Table

Account Grouping	Account Description	2009	2008 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-27,515	-27,802	286	1.0%
	4082-Retail Services Revenues	-15,101	-14,073	-1,029	(7.3%)
	4084-Service Transaction Requests (STR) Revenues	-20	-457	437	95.7%
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-41,996	-40,534	-1,462	(3.6%)
	4225-Late Payment Charges	-45,304	-27,322	-17,982	(65.8%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-46,740	-43,851	-2,889	(6.6%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-114,407	-83,827	-30,580	(36.5%)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property		-13,375	13,375	100.0%
	4390-Miscellaneous Non-Operating Income	-17,388	-9,277	-8,111	(87.4%)
3200-Investment Income	4405-Interest and Dividend Income	-186,944	-148,561	-38,383	(25.8%)

Other Revenue Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-27,802	-27,783	-18	(0.1%)
	4082-Retail Services Revenues	-14,073	-11,223	-2,850	(25.4%)
	4084-Service Transaction Requests (STR) Revenues	-457	-550	93	17.0%
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-40,534	-39,881	-654	(1.6%)
	4225-Late Payment Charges	-27,322	-30,603	3,281	10.7%
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-43,851	-49,140	5,289	10.8%
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-83,827	-47,034	-36,793	(78.2%)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property	-13,375		-13,375	
	4390-Miscellaneous Non-Operating Income	-9,277	-6,019	-3,258	(54.1%)
3200-Investment Income	4405-Interest and Dividend Income	-148,561	-174,670	26,109	14.9%

Other Revenue Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-27,783	-29,327	1,544	5.3%
	4082-Retail Services Revenues	-11,223	-9,078	-2,145	(23.6%)
	4084-Service Transaction Requests (STR) Revenues	-550	-1,079	529	49.0%
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-39,881	-49,230	9,349	19.0%
	4225-Late Payment Charges	-30,603	-25,610	-4,994	(19.5%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-49,140	-39,135	-10,005	(25.6%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-47,034	-45,180	-1,853	(4.1%)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property				
	4390-Miscellaneous Non-Operating Income	-6,019	-9,681	3,662	37.8%
3200-Investment Income	4405-Interest and Dividend Income	-174,670	-125,666	-49,003	(39.0%)

Other Revenue Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-29,327		-29,327	
	4082-Retail Services Revenues	-9,078	-1,890	-7,188	(380.3%)
	4084-Service Transaction Requests (STR) Revenues	-1,079	-11	-1,068	(9706.8%)
	4090-Electric Services Incidental to Energy Sales		-30,317	30,317	100.0%
3100-Other Operating Revenues	4210-Rent from Electric Property	-49,230		-49,230	
	4225-Late Payment Charges	-25,610	-23,883	-1,727	(7.2%)
	4230-Sales of Water and Water Power		-18,892	18,892	100.0%
	4235-Miscellaneous Service Revenues	-39,135	-34,410	-4,725	(13.7%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-45,180	-54,009	8,829	16.3%
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		11,681	-11,681	(100.0%)
	4355-Gain on Disposition of Utility and Other Property				
	4390-Miscellaneous Non-Operating Income	-9,681	-1,844	-7,837	(425.0%)
3200-Investment Income	4405-Interest and Dividend Income	-125,666	-101,282	-24,384	(24.1%)

REVENUE OFFSETS

Attachment 1 shows the revenue amounts which offset the base revenue requirement for 2010.

All sources of other revenue fully offset the base revenue requirement, except for account 4355-Gain on Disposition of Utility and Other Property, where 50% of the projected amount has been specified as the offset. This treatment is consistent with the section 4.6.1 of the Board's 2006 EDR Handbook, which states: *A capital gain or loss that falls below the materiality threshold shall be shared between the ratepayers and the shareholders on a 50/50 basis in determining the revenue requirement*.[1]

[1] 2006 Electricity Distribution Handbook, May 11, 2005, page 28

Test Year Revenue Offsets

Account Grouping	Account Description	2010 (proposed rates)		
		Service Projection	**Other (+ / -)**	**Total**
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	27,515		27,515
	4082-Retail Services Revenues	15,105		15,105
	4084-Service Transaction Requests (STR) Revenues	23		23
3100-Other Operating Revenues	4210-Rent from Electric Property		42,000	42,000
	4225-Late Payment Charges	45,000		45,000
	4235-Miscellaneous Service Revenues	47,325		47,325
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		70,000	70,000
	4355-Gain on Disposition of Utility and Other Property		12,000	12,000
	4390-Miscellaneous Non-Operating Income		15,000	15,000
3200-Investment Income	4405-Interest and Dividend Income		110,000	110,000
TOTAL		**134,968**	**249,000**	**383,968**

Test Year Revenue Offsets

Service Projections from Sheet C8

Account Grouping	Account Description	Offset Input %	or	$	2010 Offset Amount
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	100%			27,515
	4082-Retail Services Revenues	100%			15,105
	4084-Service Transaction Requests (STR) Revenues	100%			23
3100-Other Operating Revenues	4210-Rent from Electric Property	100%			42,000
	4225-Late Payment Charges	100%			45,000
	4235-Miscellaneous Service Revenues	100%			47,325
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	100%			70,000
	4355-Gain on Disposition of Utility and Other Property	50%			6,000
	4390-Miscellaneous Non-Operating Income	100%			15,000
3200-Investment Income	4405-Interest and Dividend Income	100%			110,000
TOTAL					**377,968**

Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Manager's Summary

OVERALL COST TRENDS

Attachment 1 presents the trend in ORPC's operating costs.

Operation, Maintenance and Administration ("OM&A")

An overview of ORPC's OM&A is provided in Table 1 of Exhibit 4, Tab 1, Schedule 2. As that table indicates, ORPC's proposed OM&A for 2010, excluding one-time items, reflects a 6.2% annual growth rate over its 2008 results. The drivers of major year over year changes in OM&A are described in Exhibit 4, Tab 1, Schedule 4. ORPC submits that the expected growth in its spending is prudent and reasonable, as it relates principally to the need to recruit, train and retain qualified staff to support safety, reliability and effective management.

Amortization Expense

The Attachment presents ORPC's amortization expense for rate-setting purposes, which reflects the half-year rule for all years except the 2006 Board-approved amount, where the half year rule was not applied in setting rates. The variance between the 2006 actual expense and the Board-approved amount is primarily due to the effect of the half-year rule. Amortization expense grew consistently from 2006 to 2009, reflecting increased capital investments. This trend is expected to continue in 2010, with the increase largely attributable to new investment in transportation equipment.

Information on investments driving amortization expense can be found in Exhibit 2, Tab 4. ORPC's depreciation policy is described in Exhibit 2, Tab 2, Schedule 3.

Provision In Lieu of Taxes ("PILs")

Actual PILs expense in 2006 exceeded the Board-approved amount, due to lower distribution expenses and higher miscellaneous revenues which increased taxable income. PILs expense declined from 2006 to 2009: expenses grew more than revenues, as a result taxable income decreased during this period. Income tax rates declined during this time, also leading to lower PILs expense. A further decrease in PILs expense is projected for 2010, as income tax rates continue to decline.

Further details on PILs expenses are provided in Exhibit 4, Tab 8.

Extraordinary and Other Items

ORPC has not recorded and does not foresee any extraordinary or other spending.

Operating Costs Trend Table

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009	2010
3500-Distribution Expenses - Operation	368,413	318,980	313,818	339,943	330,998	360,476
3550-Distribution Expenses - Maintenance	298,526	442,981	501,851	559,145	613,327	705,409
3650-Billing and Collecting	459,406	462,382	483,315	579,115	590,073	616,443
3700-Community Relations	51,448	63,656	51,295	71,503	43,859	58,624
3800-Administrative and General Expenses	970,222	715,572	932,823	711,400	738,324	859,815
3950-Taxes Other Than Income Taxes						-29,915
OM&A Expenses	**2,148,015**	**2,003,572**	**2,283,102**	**2,261,106**	**2,316,581**	**2,570,853**
3850-Amortization Expense *(see note below)*	773,621	$718,286	696,436	756,196	788,522	791,805
4000-Income Taxes	42,600	260,775	98,220	92,372	72,916	56,851
4100-Extraordinary & Other Items						

Note: Amortization expense for Actuals and 2010 Projection reflects half-year rule for rate-setting purposes

OM&A TEST YEAR LEVELS

As explained in Exhibit 4, Tab 2, Schedule 2, ORPC's proposed expenses in 2010 for Operations, Maintenance and Administration ("OM&A") include one-time impacts for rate filings, the transition to IFRS and the elimination of the Provincial Sales Tax ("PST"). The following table presents ORPC's OM&A expenses from 2008 to 2010, adjusted for the one-time costs and savings:

Table 1: 2008-2010 OM&A Expenses

	2008	2009	2010
Total OM&A	**$ 2,261,106**	**$ 2,316,581**	**$ 2,570,853**
Adjustments for one-time costs/savings:			
Rate Filing			$ (37,000)
Transition to IFRS			(15,000)
Elimination of PST			29,915
Total Adjustments			$ (22,085)
Adjusted OM&A	**$ 2,261,106**	**$ 2,316,581**	**$ 2,548,768**
% year/year change		*2.5%*	*10.0%*
% compound annual growth			*6.2%*

The specific reasons for the increase in 'Adjusted OM&A' (excluding one-time costs and savings) are included in ORPC's Cost Drivers, as explained in Schedule 4 of this Exhibit / Tab. The two most significant factors driving this increase are:

- the recruitment and training of trade apprentices, to address recent and expected staff retirements; and
- salary adjustments to bring compensation levels of management and administrative staff in line with those of cohorts

CONSERVATION & DEMAND MANAGEMENT PROGRAMS

ORPC delivers the following Conservation & Demand Management ("CDM") programs in association with the Ontario Power Authority ("OPA"):

- Great Refrigerator Roundup
- Energy Retrofit Incentive Plan (ERIP)
- Power Savings Blitz

Net revenues from these programs are nominal: approximately $8,000 was realized in 2009. ORPC recorded these revenues as credits to its Administrative & General Expenses. No such amounts were considered in ORPC's projections for the 2010 test year.

At this time, ORPC is not requesting any funding through distribution rates for CDM activities. ORPC expects to prepare a plan to adhere to its deemed conditions of license, including the achievement of demand and energy savings targets to be allocated by the Board in accordance with the ministerial directive,[1] and compliance with a new *CDM Code for Electricity Distributors*[2] as well as any other regulatory requirements relating to CDM. As part of this plan, ORPC will consider the appropriate mechanisms and extent of any funding from its ratepayers for CDM activities.

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[1] Directive of the Minister of Energy and Infrastructure to the Ontario Energy Board, March 31, 2010

[2] On June 22, 2010, the Board issued a Notice of Proposal to Issue a New Code, for the creation of a CDM Code for Electricity Distributors (EB-2010-0215).

COST DRIVERS

The impact of significant cost drivers on Operation, Maintenance and Administration ("OM&A") expenses is presented in Exhibit 4, Tab 2, Schedule 1, Attachment 3.

Projected OM&A expenses in 2010 are approximately $310K higher than the 2008 actual amount. The most significant drivers of this increase are as follows:

1) Increased costs for staff compensation ($181K), largely due to salary adjustments to bring the salaries of non-union staff in line with those of cohorts, as explained in Exhibit 4, Tab 4, Schedule 1

2) Additional costs for the recruitment and training of apprentices ($134K), in order to maintain a reliable distribution system and worker/public safety, in light of recent and upcoming trade staff retirements

3) The net impact of one-time costs and savings in 2010 ($22K), as summarized in Table 1 of Exhibit 4, Tab 1, Schedule 2 and further explained in Exhibit 4, Tab 2, Schedule 2.

Exhibit 4: Operating Costs

Tab 2 (of 8): Summary and Cost Driver Tables

OM&A EXPENSE TABLES

The following tables provide further details and analysis of historical and projected OM&A expenses:

- Attachment 1: Summary of OM&A expenses
- Attachment 2: Detailed Account by Account OM&A Expenses
- Attachment 3: OM&A Cost Drivers
- Attachment 4: Regulatory Costs
- Attachment 5: OM&A per Customer and per Full Time Equivalent

Summary of OM&A Expenses

Account Grouping	2010	2009	Var $	Var %
3500-Distribution Expenses - Operation	360,476	330,998	29,478	8.9%
3550-Distribution Expenses - Maintenance	705,409	613,327	**92,082**	**15.0%**
3650-Billing and Collecting	616,443	590,073	26,370	4.5%
3700-Community Relations	58,624	43,859	14,765	33.7%
3800-Administrative and General Expenses	859,815	738,324	**121,492**	**16.5%**
3950-Taxes Other Than Income Taxes	-29,915		-29,915	
OM&A Expenses	**2,570,853**	**2,316,581**	**254,272**	**11.0%**

2010 vs 2006 EDR Approved:	***19.7%***
2006-09 Actual Average % change	***5.1%***
2006-09 Compound Annual Growth	***5.0%***

Summary of OM&A Expense

Account Grouping	2009	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	330,998	339,943	-8,945	(2.6%)
3550-Distribution Expenses - Maintenance	613,327	559,145	**54,182**	**9.7%**
3650-Billing and Collecting	590,073	579,115	10,958	1.9%
3700-Community Relations	43,859	71,503	-27,644	(38.7%)
3800-Administrative and General Expenses	738,324	711,400	26,924	3.8%
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**2,316,581**	**2,261,106**	**55,475**	**2.5%**

Summary of OM&A Expense

Account Grouping	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	339,943	313,818	26,125	8.3%
3550-Distribution Expenses - Maintenance	559,145	501,851	**57,294**	**11.4%**
3650-Billing and Collecting	579,115	483,315	**95,800**	**19.8%**
3700-Community Relations	71,503	51,295	20,208	39.4%
3800-Administrative and General Expenses	711,400	932,823	**-221,423**	**(23.7%)**
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**2,261,106**	**2,283,102**	**-21,996**	**(1.0%)**

Summary of OM&A Expense

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	313,818	318,980	-5,162	(1.6%)
3550-Distribution Expenses - Maintenance	501,851	442,981	**58,870**	**13.3%**
3650-Billing and Collecting	483,315	462,382	20,932	4.5%
3700-Community Relations	51,295	63,656	-12,361	(19.4%)
3800-Administrative and General Expenses	932,823	715,572	**217,252**	**30.4%**
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**2,283,102**	**2,003,572**	**279,530**	**14.0%**

Summary of OM&A Expense

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	318,980	368,413	-49,433	(13.4%)
3550-Distribution Expenses - Maintenance	442,981	298,526	**144,455**	**48.4%**
3650-Billing and Collecting	462,382	459,406	2,976	0.6%
3700-Community Relations	63,656	51,448	12,208	23.7%
3800-Administrative and General Expenses	715,572	970,222	**-254,650**	**(26.2%)**
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**2,003,572**	**2,148,015**	**-144,443**	**(6.7%)**

Detailed Account by Account OM&A Expenses

	2006	2007	2008	2009	2010
3500- Distribution Expense- Operation	Detailed Account by Account OM&A Expenses				
5005-Operation Supervision and Engineering	56,727	46,584	55,361	53,266	58,733
5010-Load Dispatching	39,592	42,245	47,562	40,339	50,458
5012-Station Buildings and Fixtures Expense	131,576	139,025	133,683	154,222	141,543
5016-Distribution Station Equipment - Operation Labour	335		947	1,030	1,005
5017-Distribution Station Equipment - Operation Supplies and Expenses			1,967		2,200
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		1,972	1,507	618	1,599
5030-Overhead Subtransmission Feeders - Operation	1,409		46		49
5035-Overhead Distribution Transformers- Operation		928	399	348	423
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses		642	15	144	16
5055-Underground Distribution Transformers - Operation		151	69		73
5065-Meter Expense	53,613	41,048	50,898	51,570	53,997
5070-Customer Premises - Operation Labour	8,915	7,163	6,993	8,019	7,419
5075-Customer Premises - Materials and Expenses	5,958	6,080	7,016	8,395	7,443
5085-Miscellaneous Distribution Expense	20,855	27,979	33,480	13,047	35,519

Detailed Account by Account OM&A Expenses

	2006	2007	2008	2009	2010
3550- Distribution Expense- Maintenance					
5105-Maintenance Supervision and Engineering	6,300	6,484	6,323	7,126	7,839
5110-Maintenance of Buildings and Fixtures - Distribution Stations	22,605		23,044	26,015	24,447
5114-Maintenance of Distribution Station Equipment	77,505	156,243	72,433	122,578	76,844
5120-Maintenance of Poles, Towers and Fixtures	40,522	24,916	12,069	17,530	12,804
5125-Maintenance of Overhead Conductors and Devices	116,435	93,027	184,537	181,540	291,857
5130-Maintenance of Overhead Services	9,588	31,184	33,113	57,158	50,130
5135-Overhead Distribution Lines and Feeders - Right of Way	119,492	149,907	151,967	115,275	161,222
5145-Maintenance of Underground Conduit	2,927	103		414	
5150-Maintenance of Underground Conductors and Devices	26,153	4,894	27,869	15,232	29,566
5155-Maintenance of Underground Services	5,919	2,082	19,816	11,007	21,023
5160-Maintenance of Line Transformers	15,534	32,269	27,973	59,452	29,677
5175-Maintenance of Meters		742			
3650- Billing and Collecting					
5310-Meter Reading Expense	107,617	104,754	107,278	84,614	92,805
5315-Customer Billing	202,521	209,771	297,520	321,239	330,619
5320-Collecting	138,800	144,094	138,313	147,914	153,719
5330-Collection Charges	-11,717	-16,433	-15,083	-16,357	-16,500
5335-Bad Debt Expense	26,603	43,521	53,092	54,806	58,000
5340-Miscellaneous Customer Accounts Expenses	-1,442	-2,393	-2,006	-2,143	-2,200
5410-Community Relations - Sundry	21,507	13,306	34,537	21,218	28,716
5415-Energy Conservation	21,061	20,507	8,775		
5420-Community Safety Program	21,088	17,482	28,191	22,591	29,908
5515-Advertising Expense				50	

Detailed Account by Account OM&A Expenses

	2006	2007	2008	2009	2010
3800- Administration and General					
5605-Executive Salaries and Expenses	36,504	38,268	40,259	38,322	40,750
5610-Management Salaries and Expenses	246,887	239,264	216,880	245,702	274,897
5615-General Administrative Salaries and Expenses	181,676	185,023	176,285	165,641	188,683
5620-Office Supplies and Expenses	69,787	53,408	50,162	52,399	51,070
5630-Outside Services Employed	37,177	32,033	6,068	11,441	31,500
5635-Property Insurance	7,453	7,268	7,910	9,192	9,376
5645-Employee Pensions and Benefits	16,082	254,428	70,278	78,235	82,000
5655-Regulatory Expenses	36,983	38,134	53,748	50,591	87,000
5665-Miscellaneous General Expenses	223				
5670-Rent	11,150		11,891	10,993	12,000
5675-Maintenance of General Plant	64,052	80,041	70,423	68,550	74,539
5680-Electrical Safety Authority Fees	7,598	4,956	7,497	7,258	8,000
3950- Taxes Other Than Income Taxes					
6105-Taxes Other Than Income Taxes					-29,915
TOTAL OM&A	**2,003,572**	**2,283,102**	**2,261,106**	**2,316,581**	**2,570,853**

OM&A Cost Drivers

	2006	2007	2008	2009	2010
Opening Balance *	**2,148,015**	**2,003,572**	**2,283,102**	**2,261,106**	**2,316,581**
Staff wages & benefits	80,854	9,373	22,328	100,841	80,465
Staff changes: Apprentices wages & training	-20,000			14,159	119,929
Staff Changes : Addition of an IT Technician			49,000		
Staff Changes : Leaving of the Customer Service/Substation Supervisor		-33,022			
CDM & Safety Education				-8,775	7,317
Bad debt expense	-2,232	16,918	9,571	1,714	3,194
Low Voltage reclass to Cost of Power	-216,619				
Audit / Accounting / Tax filings	12,000				
Regulatory expenses	29,821				37,000
Financial system costs					15,000
Meter Reading	7,446		3,531	-22,665	8,191
Cost Allocation Study - Hydro One	11,500				
Vested Sick Leave Adjustment		224,634	-224,634		
Substation Maintenance		31,822		50,145	
Distribution Transformers		16,734			
PST Cost Savings					-29,915
Meter Re-Verifications	-26,000				
Legal Fees	-32,125				
CIS Costs			21,380		
Underground Maintenance			18,975	-18,975	
Line Maintenance			61,011	-61,011	
Other	10,911	13,071	16,842	42	13,092
Closing Balance	**2,003,572**	**2,283,102**	**2,261,106**	**2,316,581**	**2,570,853**

** For 2006: Board-approved amount; for other years: previous year's closing balance*

Regulatory Costs

Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year (2006)	Last Year of Actuals 2008	Bridge Year 2009	% Change in bridge yr vs last yr of actuals	Test Year Forecast 2010	% Change in Test Yr vs. Bridge Yr
OEB Annual Assessment	5655			28,631	25,053	24,781	-1%	25,200	2%
OEB Hearing Assessments (applicant initiated)	5655								
OEB Section 30 Costs (OEB initiated)	5655				1,985	852	-57%	1,000	17%
Expert Witness cost for regulatory matters	5655								
Legal costs for regulatory matters	5655								
Consultants cost for regulatory matters	5655							32,000	
Staff resources allocated to regulatory matters	5655								
Other regulatory agency fees or assessments	5655				800	800		800	
Intervenor Costs	5655			2,630				5,000	
Annual Auditor Fees					24,000	24,158	1%	23,000	-5%
TOTAL				**31,261**	**51,838**	**50,591**	**-2%**	**87,000**	**72%**

FILING COSTS FOR RATE APPLICATIONS

To date May 2010	34,179	
Outstanding drafting & model changes	16,821	
Production & Submission	5,000	
Public Notice	2,000	
Interrogatories	20,000	
Argument in chief	5,000	
Reply submission	5,000	
Intervenor costs	20,000	
Rate Order	10,000	
Total Filing costs	**118,000**	
IRM filing costs 2011-13	30,000	note: estimated $10K for each typical filing
Total for Rate Filings	148,000	
Annualized amount for filings	37,000	Total for Rate Filings, divided by 4 years
Annual baseline regulatory expenses	50,000	
Total annual regulatory expense	**87,000**	

OM&A per Customer and per Full Time Equivalent

	Actual			Bridge Yr	Test Yr
	2006	2007	2008	2009	2010
Number of Customers	13,131	13,182	13,265	13,330	13,371
Total OM&A	$2,003,572	$2,283,102	$2,261,106	$2,316,581	$2,570,853
OM&A cost per customer	$152.58	$173.20	$170.46	$173.79	$192.27
Number of FTEEs	25	25	25	26	27
FTEEs/Customer	0.0019	0.0019	0.0019	0.0020	0.0020
OM&A cost per FTEE	$80,142.87	$93,187.82	$90,444.23	$89,099.26	$95,216.78

ONE-TIME COSTS

ORPC projects incremental one-time costs in 2010 for this cost of service rate application, and to complete the transition to International Financial Reporting Standards (“IFRS”).

As noted in Exhibit 4, Tab 2, Schedule 3, ORPC has considered its overall projected incremental costs for rate applications of $148,000 and included one quarter of that amount in its test year projections for account ‘5655-Regulatory Expenses’, to enable full recovery over four years.

ORPC has consulted with its auditor, financial system support and similarly-situated utilities in arriving at an estimated one-time incremental cost of $60,000 to complete the transition to IFRS. One quarter of the total cost ($15,000) has been included in the test year projections for account ‘5630-Outside Services Employed’, to enable full recovery over four years.

A one-time credit of $29,915 was included in the test year projections under account ‘6105-Taxes Other Than Income Taxes’. The individual account projections did not consider the estimated savings from the elimination of the Provincial Sales Tax (“PST”). Instead, an overall projection of PST on OM&A expenses was prepared, based on PST amounts actually paid in 2009. As a result, the total test year OM&A now excludes all PST. ORPC proposes to defer for future recovery PST amounts actually paid in the first half of 2010, as explained in Exhibit 9, Tab 1, Schedule 1.

REGULATORY COSTS

Details of ORPC's regulatory costs appear in Schedule 1, Attachment 4 of this Exhibit/Tab.

ORPC estimates consulting fees of approximately $118K to complete this 2010 cost of service rate application. ORPC engaged the services of Elenchus Research Associates ("Elenchus") to assist in this process, given the limited internal resources available to work on an extensive application. As at early June 2010, ORPC has incurred about $34K in fees from Elenchus; a further $22K in costs are estimated to complete the initial filing and $62K to address the subsequent phases in the proceeding, for a total of $118K in estimated incremental costs directly associated with the 2010 rate application.

ORPC also projects average incremental costs of $10K in each of the following three IRM[1] filing years, or an aggregate amount of $30K, due to the increased efforts expected under the Board's 3rd Generation IRM e.g. revenue to cost adjustments, deferral/variance account dispositions including smart meters, additional filing requirements such as those arising from the GEGEA,[2] etc.

As a result, total rate filing costs of $148K are estimated for ORPC's upcoming four-year rebasing cycle. 25% of this amount ($37K) has been included in ORPC's test year costs, in addition to $50K in annual baseline regulatory costs, consistent with actual costs in the most recent two historical years.

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[1] Incentive Regulation Mechanism

[2] *Green Energy and Green Economy Act, 2009*

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

In March 2009, as part of its LEAP initiative, the Board determined that distributors should commit 0.12% of their Board-approved distribution revenue requirement (minimum $2,000) to financial assistance programs for low-income energy consumers.[1] With a proposed base revenue requirement of $3.9 million, ORPC's annual support for such programs would have been approximately $4,700.

However, in a letter dated September 28, 2009, the Board advised it was deferring its implementation of LEAP, following ministerial direction on the development of a province-wide integrated program for low-income energy consumers.

Accordingly, ORPC has not included any amounts in its test year distribution expenses for financial assistance to low-income energy consumers.

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[1] Report of the Board: Low-Income Energy Assistance Program (EB-2008-0150), March 10, 2009, page 10

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

ORPC expects to comply with all licensing conditions and other regulatory requirements arising from the implementation of the *Green Energy and Green Economy Act, 2009*. At this time, ORPC is not filing a Distribution System Plan with specific initiatives or quantified incremental costs. Rather, ORPC proposes to record any incremental costs associated with initiatives under this legislation to the appropriate Board-approved deferral accounts:

- 1531 – Renewable Connection Capital Deferral Account
- 1532 – Renewable Connection OM&A Deferral Account
- 1534 – Smart Grid Capital Deferral Account
- 1535 – Smart Grid OM&A Deferral Account

CHARITABLE DONATIONS

There are no amounts for charitable donations included in ORPC's proposed distribution expenses for the 2010 test year.

ORPC has a policy not to make charitable donations. Its Board of Directors has determined that it would not be prudent to use revenues from ORPC's customers to fund charitable organizations.

ORPC does however; provide assistance where its skilled expertise can aid in community activities. Staff are involved in such activities as providing equipment to erect community stages for festivals and installing municipal decorations. A number of employees volunteer their time to different causes and service organizations, for activities such as local Christmas parades, winter festival, helping to light a giant Christmas tree at a long term care facility, Relay for Life and an annual food drive for the local food bank.

Exhibit 4: Operating Costs

Tab 3 (of 8): OM&A Variance Analysis

OM&A VARIANCES TABLE

Attachment 1 presents the variance analysis of ORPC's expenses for Operations, Maintenance and Administration ("OM&A") for each individual account. A summarized view by account grouping appears in Exhibit 4, Tab 2, Schedule 1, Attachment 1.

The following sections provide explanations for material year over year variances.

2010 Test Year vs 2009 Bridge Year

OM&A expense in 2010 are projected to increase by $254K over actual 2009 expenses. The variance consists primarily of increases in Administrative and General Expenses ($121K), Distribution Expenses – Maintenance ($92K) and Distribution Expenses – Operation ($29K).

The variance in Administrative and General Expenses is principally attributable to:

- Management salary increases for five management staff to bring salaries to the level of their cohorts following a review by the Board of Directors (see Exhibit 4, Tab 4, Schedule 1): $59K.
- 25% of costs associated with the 2010 cost of service application: $37K
- 25% costs associated with the transition to International Financial Reporting Standards ("IFRS"): $15K

The variance in Distribution Operation and Maintenance Expenses is principally attributable to the costs associated with the hiring and training of four new line apprentices and one new meter technician apprentice. These apprentices are being hired to replace the retirement of the line superintendent (Pembroke) who retired on May 1, 2010, the working foreman (Almonte) who anticipates retiring at the end of 2010, a journeyman in the Pembroke department planning to retire in 2012 and the meter technician who is expected to retire in 2013. The incremental costs reflect the need for additional staff over several years, and training costs associated with bringing skill levels to those of a full lineman/journeyman. These costs were forecasted from 2010 through 2013, with 25% aggregate amount included in the 2010 test year projections.

2009 Bridge Year vs 2008 Historical Actual

OM&A expenses in 2009 increased by $55K from 2008 actual expenses. The variance consists primarily of higher costs for Distribution Expenses – Maintenance ($54K), which was principally attributed to increased maintenance of substation buildings and equipment due to the work completed on breakers at Substation 4, fencing work (pillars) at Substation 8 and block work need to repair Substation 1.

2008 Historical Actual vs 2007 Historical Actual

OM&A expenses in 2008 decreased by $22K from 2007 actual expenses. The decrease was due to lower Administrative & General Expenses ($221K), largely offset by increased costs for Billing & Collecting ($96K) and Distribution Expenses – Maintenance ($57K).

The decrease in Administrative & General Expenses was principally attributed to the reversal of a one-time accrual in 2007 for vested sick leave, following a decision by ORPC's Board of Directors to discontinue the practice.

The variance in Billing & Collecting expenses was principally attributed to:

- The implementation of a new Customer Information System with increased software maintenance, increased labour by all office staff to learn the new system, and the shifting of the officer manager's time from administration to billing to spearhead the project: $78K
- The implementation and ongoing costs of the Utilismart Settlement System: $11K

The variance in Distribution Expenses – Maintenance was mainly due to increased maintenance activities for overhead lines, underground plant and substations. Capital work requirements were lower in 2008, enabling a shift in labour to these maintenance programs so as to maintain the distribution system in a safe and reliable manner. As well, $10K in additional costs were incurred to bring the utility's mapping system up to date.

2007 Historical Actual vs 2006 Historical Actual

OM&A expenses in 2007 increased by $280K over 2006 actual expenses. The variance consists primarily of higher costs for Administrative & General Expenses ($217K) and Distribution Expenses – Maintenance ($59K).

The variance in Administrative and General Expenses was principally attributed to a vested sick leave accrual adjustment; as such costs were historically incurred in the year of the manager's retirement.

The variance in Distribution Expenses – Maintenance was mainly due to

- Increased substation maintenance for the removal of contaminated oil: $31K
- Increased costs for PCB testing of distribution transformers: $17K

2006 Historical Actual vs 2006 EDR Board-Approved

The 2006 EDR Board-approved amount for OM&A included an adjustment of $217K for low voltage charges, reflected under Administrative & General Expenses. Excluding this adjustment, actual OM&A expense in 2006 was $72K higher than the Board-approved amount. The variance consists primarily of higher costs for Distribution Expenses – Maintenance ($144K), partially offset by lower costs for Distribution Expenses – Operation ($49K) and Administrative & General Expenses ($38K).

The variance in Distribution Expenses – Maintenance was principally attributed to:

- Increased tree trimming activity, due to a catch up in the program from 2004 $60K
- Emergency repairs following four separate summer storms with high winds: $50K
- Increased underground maintenance, due to a full inspection of the underground system complete with identification and labeling: $23K

The variance in Distribution Expenses – Operation was mainly due to:

- Decreased meter operation expenses, due to a more typical level of expense compared to 2004, when a significant increase of meter re-verifications were completed: $26K.
- Decrease in substation & line training for apprentices who had completed their training in 2004: $20K

The variance in Administration & General Expense arose primarily from reduced costs for legal expenses (outside services), compared with previous higher levels that had arisen from amalgamation and market opening.

OM&A Variances Table

Account Grouping	Account Description	2010	2009	Var $	Var %
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	58,733	53,266	5,467	10.3%
	5010-Load Dispatching	50,458	40,339	10,119	25.1%
	5012-Station Buildings and Fixtures Expense	141,543	154,222	-12,679	(8.2%)
	5016-Distribution Station Equipment - Operation Labour	1,005	1,030	-25	(2.5%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	2,200		2,200	
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,599	618	981	158.7%
	5030-Overhead Subtransmission Feeders - Operation	49		49	
	5035-Overhead Distribution Transformers- Operation	423	348	75	21.6%
	5040-Underground Distribution Lines and Feeders - Operation Labour				
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	16	144	-128	(89.1%)
	5055-Underground Distribution Transformers - Operation	73		73	
	5065-Meter Expense	53,997	51,570	2,427	4.7%
	5070-Customer Premises - Operation Labour	7,419	8,019	-600	(7.5%)
	5075-Customer Premises - Materials and Expenses	7,443	8,395	-952	(11.3%)
	5085-Miscellaneous Distribution Expense	35,519	13,047	22,472	172.2%

OM&A Variances Table

Account Grouping	Account Description	2010	2009	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	7,839	7,126	713	10.0%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	24,447	26,015	-1,568	(6.0%)
	5114-Maintenance of Distribution Station Equipment	76,844	122,578	-45,734	(37.3%)
	5120-Maintenance of Poles, Towers and Fixtures	12,804	17,530	-4,726	(27.0%)
	5125-Maintenance of Overhead Conductors and Devices	291,857	181,540	**110,317**	**60.8%**
	5130-Maintenance of Overhead Services	50,130	57,158	-7,028	(12.3%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	161,222	115,275	45,947	39.9%
	5145-Maintenance of Underground Conduit		414	-414	(100.0%)
	5150-Maintenance of Underground Conductors and Devices	29,566	15,232	14,334	94.1%
	5155-Maintenance of Underground Services	21,023	11,007	10,016	91.0%
	5160-Maintenance of Line Transformers	29,677	59,452	-29,775	(50.1%)
	5175-Maintenance of Meters				
3650-Billing and Collecting	5310-Meter Reading Expense	92,805	84,614	8,191	9.7%
	5315-Customer Billing	330,619	321,239	9,380	2.9%
	5320-Collecting	153,719	147,914	5,805	3.9%
	5330-Collection Charges	-16,500	-16,357	-143	(0.9%)
	5335-Bad Debt Expense	58,000	54,806	3,194	5.8%
	5340-Miscellaneous Customer Accounts Expenses	-2,200	-2,143	-57	(2.7%)
3700-Community Relations	5410-Community Relations - Sundry	28,716	21,218	7,498	35.3%
	5415-Energy Conservation				
	5420-Community Safety Program	29,908	22,591	7,317	32.4%
	5515-Advertising Expense		50	-50	(100.0%)

OM&A Variances Table

Account Grouping	Account Description	2010	2009	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	40,750	38,322	2,428	6.3%
	5610-Management Salaries and Expenses	274,897	245,702	29,195	11.9%
	5615-General Administrative Salaries and Expenses	188,683	165,641	23,042	13.9%
	5620-Office Supplies and Expenses	51,070	52,399	-1,329	(2.5%)
	5630-Outside Services Employed	31,500	11,441	20,059	175.3%
	5635-Property Insurance	9,376	9,192	184	2.0%
	5645-Employee Pensions and Benefits	82,000	78,235	3,765	4.8%
	5655-Regulatory Expenses	87,000	50,591	36,409	72.0%
	5665-Miscellaneous General Expenses				
	5670-Rent	12,000	10,993	1,007	9.2%
	5675-Maintenance of General Plant	74,539	68,550	5,989	8.7%
	5680-Electrical Safety Authority Fees	8,000	7,258	742	10.2%
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	-29,915		-29,915	
TOTAL OM&A		**2,570,853**	**2,316,581**	**254,272**	**11.0%**

OM&A Variances Table

Account Grouping	Account Description	2009	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	53,266	55,361	-2,095	(3.8%)
	5010-Load Dispatching	40,339	47,562	-7,223	(15.2%)
	5012-Station Buildings and Fixtures Expense	154,222	133,683	20,539	15.4%
	5016-Distribution Station Equipment - Operation Labour	1,030	947	83	8.8%
	5017-Distribution Station Equipment - Operation Supplies and Expenses		1,967	-1,967	(100.0%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	618	1,507	-889	(59.0%)
	5030-Overhead Subtransmission Feeders - Operation		46	-46	(100.0%)
	5035-Overhead Distribution Transformers- Operation	348	399	-51	(12.8%)
	5040-Underground Distribution Lines and Feeders - Operation Labour				
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	144	15	129	871.7%
	5055-Underground Distribution Transformers - Operation		69	-69	(100.0%)
	5065-Meter Expense	51,570	50,898	672	1.3%
	5070-Customer Premises - Operation Labour	8,019	6,993	1,026	14.7%
	5075-Customer Premises - Materials and Expenses	8,395	7,016	1,379	19.7%
	5085-Miscellaneous Distribution Expense	13,047	33,480	-20,433	(61.0%)

OM&A Variances Table

Account Grouping	Account Description	2009	2008 Actual	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	7,126	6,323	803	12.7%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	26,015	23,044	2,971	12.9%
	5114-Maintenance of Distribution Station Equipment	122,578	72,433	**50,145**	**69.2%**
	5120-Maintenance of Poles, Towers and Fixtures	17,530	12,069	5,461	45.2%
	5125-Maintenance of Overhead Conductors and Devices	181,540	184,537	-2,997	(1.6%)
	5130-Maintenance of Overhead Services	57,158	33,113	24,045	72.6%
	5135-Overhead Distribution Lines and Feeders - Right of Way	115,275	151,967	-36,692	(24.1%)
	5145-Maintenance of Underground Conduit	414		414	
	5150-Maintenance of Underground Conductors and Devices	15,232	27,869	-12,637	(45.3%)
	5155-Maintenance of Underground Services	11,007	19,816	-8,809	(44.5%)
	5160-Maintenance of Line Transformers	59,452	27,973	31,479	112.5%
	5175-Maintenance of Meters				
3650-Billing and Collecting	5310-Meter Reading Expense	84,614	107,278	-22,664	(21.1%)
	5315-Customer Billing	321,239	297,520	23,718	8.0%
	5320-Collecting	147,914	138,313	9,601	6.9%
	5330-Collection Charges	-16,357	-15,083	-1,274	(8.4%)
	5335-Bad Debt Expense	54,806	53,092	1,714	3.2%
	5340-Miscellaneous Customer Accounts Expenses	-2,143	-2,006	-137	(6.8%)
3700-Community Relations	5410-Community Relations - Sundry	21,218	34,537	-13,318	(38.6%)
	5415-Energy Conservation		8,775	-8,775	(100.0%)
	5420-Community Safety Program	22,591	28,191	-5,600	(19.9%)
	5515-Advertising Expense	50		50	

OM&A Variances Table

Account Grouping	Account Description	2009	2008 Actual	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	38,322	40,259	-1,937	(4.8%)
	5610-Management Salaries and Expenses	245,702	216,880	28,822	13.3%
	5615-General Administrative Salaries and Expenses	165,641	176,285	-10,644	(6.0%)
	5620-Office Supplies and Expenses	52,399	50,162	2,237	4.5%
	5630-Outside Services Employed	11,441	6,068	5,374	88.6%
	5635-Property Insurance	9,192	7,910	1,282	16.2%
	5645-Employee Pensions and Benefits	78,235	70,278	7,957	11.3%
	5655-Regulatory Expenses	50,591	53,748	-3,157	(5.9%)
	5665-Miscellaneous General Expenses				
	5670-Rent	10,993	11,891	-898	(7.6%)
	5675-Maintenance of General Plant	68,550	70,423	-1,873	(2.7%)
	5680-Electrical Safety Authority Fees	7,258	7,497	-239	(3.2%)
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**2,316,581**	**2,261,106**	**55,475**	**2.5%**

OM&A Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	55,361	46,584	8,777	18.8%
	5010-Load Dispatching	47,562	42,245	5,316	12.6%
	5012-Station Buildings and Fixtures Expense	133,683	139,025	-5,341	(3.8%)
	5016-Distribution Station Equipment - Operation Labour	947		947	
	5017-Distribution Station Equipment - Operation Supplies and Expenses	1,967		1,967	
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,507	1,972	-465	(23.6%)
	5030-Overhead Subtransmission Feeders - Operation	46		46	
	5035-Overhead Distribution Transformers- Operation	399	928	-529	(57.0%)
	5040-Underground Distribution Lines and Feeders - Operation Labour				
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	15	642	-627	(97.7%)
	5055-Underground Distribution Transformers - Operation	69	151	-82	(54.3%)
	5065-Meter Expense	50,898	41,048	9,849	24.0%
	5070-Customer Premises - Operation Labour	6,993	7,163	-170	(2.4%)
	5075-Customer Premises - Materials and Expenses	7,016	6,080	936	15.4%
	5085-Miscellaneous Distribution Expense	33,480	27,979	5,501	19.7%

OM&A Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,323	6,484	-161	(2.5%)
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	23,044		23,044	
	5114-Maintenance of Distribution Station Equipment	72,433	156,243	**-83,810**	(53.6%)
	5120-Maintenance of Poles, Towers and Fixtures	12,069	24,916	-12,847	(51.6%)
	5125-Maintenance of Overhead Conductors and Devices	184,537	93,027	**91,510**	98.4%
	5130-Maintenance of Overhead Services	33,113	31,184	1,929	6.2%
	5135-Overhead Distribution Lines and Feeders - Right of Way	151,967	149,907	2,060	1.4%
	5145-Maintenance of Underground Conduit		103	-103	(100.0%)
	5150-Maintenance of Underground Conductors and Devices	27,869	4,894	22,975	469.5%
	5155-Maintenance of Underground Services	19,816	2,082	17,734	851.8%
	5160-Maintenance of Line Transformers	27,973	32,269	-4,296	(13.3%)
	5175-Maintenance of Meters		742	-742	(100.0%)
3650-Billing and Collecting	5310-Meter Reading Expense	107,278	104,754	2,524	2.4%
	5315-Customer Billing	297,520	209,771	**87,749**	41.8%
	5320-Collecting	138,313	144,094	-5,781	(4.0%)
	5330-Collection Charges	-15,083	-16,433	1,350	8.2%
	5335-Bad Debt Expense	53,092	43,521	9,571	22.0%
	5340-Miscellaneous Customer Accounts Expenses	-2,006	-2,393	387	16.2%
3700-Community Relations	5410-Community Relations - Sundry	34,537	13,306	21,231	159.6%
	5415-Energy Conservation	8,775	20,507	-11,732	(57.2%)
	5420-Community Safety Program	28,191	17,482	10,709	61.3%
	5515-Advertising Expense				

OM&A Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	40,259	38,268	1,991	5.2%
	5610-Management Salaries and Expenses	216,880	239,264	-22,384	(9.4%)
	5615-General Administrative Salaries and Expenses	176,285	185,023	-8,738	(4.7%)
	5620-Office Supplies and Expenses	50,162	53,408	-3,246	(6.1%)
	5630-Outside Services Employed	6,068	32,033	-25,965	(81.1%)
	5635-Property Insurance	7,910	7,268	641	8.8%
	5645-Employee Pensions and Benefits	70,278	254,428	**-184,150**	(72.4%)
	5655-Regulatory Expenses	53,748	38,134	15,613	40.9%
	5665-Miscellaneous General Expenses				
	5670-Rent	11,891		11,891	
	5675-Maintenance of General Plant	70,423	80,041	-9,618	(12.0%)
	5680-Electrical Safety Authority Fees	7,497	4,956	2,540	51.3%
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**2,261,106**	**2,283,102**	**-21,996**	**(1.0%)**

OM&A Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	46,584	56,727	-10,143	(17.9%)
	5010-Load Dispatching	42,245	39,592	2,653	6.7%
	5012-Station Buildings and Fixtures Expense	139,025	131,576	7,449	5.7%
	5016-Distribution Station Equipment - Operation Labour		335	-335	(100.0%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses				
	5020-Overhead Distribution Lines and Feeders - Operation Labour				
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1,972		1,972	
	5030-Overhead Subtransmission Feeders - Operation		1,409	-1,409	(100.0%)
	5035-Overhead Distribution Transformers-Operation	928		928	
	5040-Underground Distribution Lines and Feeders - Operation Labour				
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	642		642	
	5055-Underground Distribution Transformers - Operation	151		151	
	5065-Meter Expense	41,048	53,613	-12,565	(23.4%)
	5070-Customer Premises - Operation Labour	7,163	8,915	-1,752	(19.6%)
	5075-Customer Premises - Materials and Expenses	6,080	5,958	122	2.1%
	5085-Miscellaneous Distribution Expense	27,979	20,855	7,123	34.2%

OM&A Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,484	6,300	183	2.9%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations		22,605	-22,605	(100.0%)
	5114-Maintenance of Distribution Station Equipment	156,243	77,505	**78,738**	101.6%
	5120-Maintenance of Poles, Towers and Fixtures	24,916	40,522	-15,607	(38.5%)
	5125-Maintenance of Overhead Conductors and Devices	93,027	116,435	-23,408	(20.1%)
	5130-Maintenance of Overhead Services	31,184	9,588	21,596	225.2%
	5135-Overhead Distribution Lines and Feeders - Right of Way	149,907	119,492	30,415	25.5%
	5145-Maintenance of Underground Conduit	103	2,927	-2,823	(96.5%)
	5150-Maintenance of Underground Conductors and Devices	4,894	26,153	-21,259	(81.3%)
	5155-Maintenance of Underground Services	2,082	5,919	-3,837	(64.8%)
	5160-Maintenance of Line Transformers	32,269	15,534	16,734	107.7%
	5175-Maintenance of Meters	742		742	
3650-Billing and Collecting	5310-Meter Reading Expense	104,754	107,617	-2,863	(2.7%)
	5315-Customer Billing	209,771	202,521	7,249	3.6%
	5320-Collecting	144,094	138,800	5,294	3.8%
	5330-Collection Charges	-16,433	-11,717	-4,716	(40.2%)
	5335-Bad Debt Expense	43,521	26,603	16,918	63.6%
	5340-Miscellaneous Customer Accounts Expenses	-2,393	-1,442	-951	(65.9%)
3700-Community Relations	5410-Community Relations - Sundry	13,306	21,507	-8,201	(38.1%)
	5415-Energy Conservation	20,507	21,061	-555	(2.6%)
	5420-Community Safety Program	17,482	21,088	-3,606	(17.1%)
	5515-Advertising Expense				

OM&A Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	38,268	36,504	1,764	4.8%
	5610-Management Salaries and Expenses	239,264	246,887	-7,623	(3.1%)
	5615-General Administrative Salaries and Expenses	185,023	181,676	3,347	1.8%
	5620-Office Supplies and Expenses	53,408	69,787	-16,379	(23.5%)
	5630-Outside Services Employed	32,033	37,177	-5,145	(13.8%)
	5635-Property Insurance	7,268	7,453	-185	(2.5%)
	5645-Employee Pensions and Benefits	254,428	16,082	**238,346**	1482.0%
	5655-Regulatory Expenses	38,134	36,983	1,151	3.1%
	5665-Miscellaneous General Expenses		223	-223	(100.0%)
	5670-Rent		11,150	-11,150	(100.0%)
	5675-Maintenance of General Plant	80,041	64,052	15,989	25.0%
	5680-Electrical Safety Authority Fees	4,956	7,598	-2,641	(34.8%)
	5685-Independent Market Operator Fees and Penalties				
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**2,283,102**	**2,003,572**	**279,530**	**14.0%**

OM&A Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	56,727	58,407	-1,680	(2.9%)
	5010-Load Dispatching	39,592	32,872	6,720	20.4%
	5012-Station Buildings and Fixtures Expense	131,576	133,535	-1,959	(1.5%)
	5016-Distribution Station Equipment - Operation Labour	335	801	-466	(58.1%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses				
	5020-Overhead Distribution Lines and Feeders - Operation Labour		801	-801	(100.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses				
	5030-Overhead Subtransmission Feeders - Operation	1,409	801	608	75.9%
	5035-Overhead Distribution Transformers-Operation				
	5040-Underground Distribution Lines and Feeders - Operation Labour		1,601	-1,601	(100.0%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses				
	5055-Underground Distribution Transformers - Operation				
	5065-Meter Expense	53,613	80,078	-26,465	(33.0%)
	5070-Customer Premises - Operation Labour	8,915	10,511	-1,596	(15.2%)
	5075-Customer Premises - Materials and Expenses	5,958	2,203	3,755	170.4%
	5085-Miscellaneous Distribution Expense	20,855	46,803	-25,948	(55.4%)

OM&A Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	6,300	5,050	1,250	24.8%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	22,605	25,267	-2,662	(10.5%)
	5114-Maintenance of Distribution Station Equipment	77,505	83,442	-5,937	(7.1%)
	5120-Maintenance of Poles, Towers and Fixtures	40,522	32,104	8,418	26.2%
	5125-Maintenance of Overhead Conductors and Devices	116,435	40,665	**75,770**	186.3%
	5130-Maintenance of Overhead Services	9,588	7,164	2,424	33.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	119,492	59,427	**60,065**	101.1%
	5145-Maintenance of Underground Conduit	2,927	3,882	-956	(24.6%)
	5150-Maintenance of Underground Conductors and Devices	26,153	2,961	23,192	783.2%
	5155-Maintenance of Underground Services	5,919	5,959	-40	(0.7%)
	5160-Maintenance of Line Transformers	15,534	32,570	-17,036	(52.3%)
	5175-Maintenance of Meters		35	-35	(100.0%)
3650-Billing and Collecting	5310-Meter Reading Expense	107,617	100,698	6,919	6.9%
	5315-Customer Billing	202,521	216,538	-14,017	(6.5%)
	5320-Collecting	138,800	119,041	19,759	16.6%
	5330-Collection Charges	-11,717	-8,009	-3,708	(46.3%)
	5335-Bad Debt Expense	26,603	28,835	-2,232	(7.7%)
	5340-Miscellaneous Customer Accounts Expenses	-1,442	2,303	-3,745	(162.6%)
3700-Community Relations	5410-Community Relations - Sundry	21,507	33,197	-11,690	(35.2%)
	5415-Energy Conservation	21,061		21,061	
	5420-Community Safety Program	21,088	17,448	3,640	20.9%
	5515-Advertising Expense		803	-803	(100.0%)

OM&A Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	36,504	41,037	-4,533	(11.0%)
	5610-Management Salaries and Expenses	246,887	240,853	6,034	2.5%
	5615-General Administrative Salaries and Expenses	181,676	185,410	-3,734	(2.0%)
	5620-Office Supplies and Expenses	69,787	47,050	22,737	48.3%
	5630-Outside Services Employed	37,177	69,302	-32,125	(46.4%)
	5635-Property Insurance	7,453	9,821	-2,368	(24.1%)
	5645-Employee Pensions and Benefits	16,082	9,423	6,659	70.7%
	5655-Regulatory Expenses	36,983	47,825	-10,842	(22.7%)
	5665-Miscellaneous General Expenses	223	216,619	**-216,396**	(99.9%)
	5670-Rent	11,150	13,037	-1,887	(14.5%)
	5675-Maintenance of General Plant	64,052	64,904	-852	(1.3%)
	5680-Electrical Safety Authority Fees	7,598	9,123	-1,525	(16.7%)
	5685-Independent Market Operator Fees and Penalties		15,818	-15,818	(100.0%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**2,003,572**	**2,148,015**	**-144,443**	**(6.7%)**

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation

STAFFING AND COMPENSATION LEVELS

Attachment 1 presents a breakdown of ORPC's staffing levels and employee compensation costs. The executive salary is aggregated with management salaries, in accordance with Board policy that states: *Where there are three or fewer employees in any category, the applicant may aggregate this category with the category to which it is most closely related.*[1]

In 2008, the human resources committee of ORPC's Board of Directors started a review of the salaries for executive, management and administrative staff. The committee initially did a comparison of the president's salary with those in surrounding utilities and utilities of a similar size, as well as salaries of local executives. As a result of this review, the president's salary was adjusted in late 2008. In 2009 the committee began their review of the other salaries mentioned above. ORPC took part in a 2009 compensation survey conducted by MEARIE:[2] the committee examined the report of the survey's findings, as well as other local comparators. These employees had a salary adjustment effective April 1, 2010 with another increase planned for July 1, 2010. The committee plans to make further adjustments to certain management salaries over a number of years, in order to bring these to their cohorts' levels.

ORPC also employs three other non-union employees (two full-time and one part-time) whose compensation levels are reviewed by the president and the Board of Directors. In addition, ORPC employs 17 full-time unionized workers who are remunerated according to a collective agreement that is negotiated every three years.

During 2007, the customer service manager went onto long-term disability and has not returned to work. The IT manager officially took over the customer service manager's

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[1] Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009, page 15

[2] MEARIE: Municipal Electric Association Reciprocal Insurance Exchange

duties and responsibilities in May 2007 when the disability claim was approved by Great West Life. As a result, the management team decreased from 6 to 5.5 full-time equivalent employees. Later that year ORPC determined that another manager was not necessary, but that an IT technician was required to alleviate the work load burden on the IT/Customer Service manager. The technician was hired in February 2008.

In June 2009 a line apprentice was hired for the Pembroke area in preparation for the May 2010 retirement of the line superintendent. The superintendent position was posted both internally and externally, with the successful candidate being promoted from the Pembroke staff. A second line apprentice was hired in May 2010, also for the Pembroke office, in preparation for another journeyman retirement expected within a few years. A third apprentice (3rd year apprentice) has been hired for the Almonte area, as the working foreman in Almonte is expected to retire in December 2010. The following table summarizes current staffing levels by department:

Table 1: Staffing Levels by Department

Management	5
Line Department	8
Service Department	4
Office Staff, Admin & IT	9

ORPC pays 100% of the costs of the MEARIE Extended Health Care Plan, Dental Plan, Vision Plan, Life Insurance and Long Term Disability Plan. All electricity distributors in Ontario are required to participate in the retirement plan administered by the Ontario Municipal Employees Retirement System (“OMERS”), under which employees fund 50% of plan contributions with the employer funding the other 50%.

Employee Costs Table

	2006 EDR	2006	2007	2008	2009	2010
Number of Employees (FTEs including Part-Time)						
Management	6.0	6.0	5.5	5.0	5.0	5.5
Non-Union	2.0	2.0	2.0	3.0	3.0	3.0
Union	17.0	17.0	17.0	17.0	18.0	18.5
Total	**25.0**	**25.0**	**24.5**	**25.0**	**26.0**	**27.0**
Number of Part-Time Employees						
Management						
Non-Union	1	1	1	1	1	1
Union						
Total	1	1	1	1	1	1
Total Salary and Wages						
Management	456,840	438,844	411,232	419,475	436,215	501,086
Non-Union	93,558	98,655	101,581	162,933	161,322	170,812
Union	805,851	904,001	899,172	957,419	1,025,871	1,082,062
Total	**1,356,249**	**1,441,500**	**1,411,986**	**1,539,827**	**1,623,408**	**1,753,960**
Total Benefits						
Management	52,358	60,581	54,908	54,675	56,851	62,896
Non-Union	15,382	16,250	16,687	23,491	24,433	24,597
Union	143,152	152,469	156,899	172,082	176,596	180,220
Total	**210,892**	**229,300**	**228,494**	**250,248**	**257,880**	**267,713**
Total Compensation (Salary, Wages, & Benefits)						
Management	509,198	499,424	466,140	474,150	493,065	563,981
Non-Union	108,940	114,906	118,268	186,424	185,754	195,409
Union	949,003	1,056,470	1,056,071	1,129,501	1,202,468	1,262,282
Total	**1,567,140**	**1,670,800**	**1,640,480**	**1,790,075**	**1,881,287**	**2,021,673**

Employee Costs Table

	2006 EDR	2006	2007	2008	2009	2010
Compensation - Average Yearly Base Wages						
Management	66,036	70,596	73,934	74,989	82,351	87,106
Non-Union	37,109	49,328	50,791	54,311	53,774	56,937
Union	44,098	48,500	49,735	51,734	50,457	51,990
Total	**147,243**	**168,424**	**174,460**	**181,034**	**186,582**	**196,034**
Compensation - Average Yearly Overtime						
Management	4,248	2,544	835	8,906	4,892	4,000
Non-Union	NIL	NIL	NIL	NIL	NIL	NIL
Union	2,390	4,676	3,157	4,584	6,535	6,500
Total	**6,638**	**7,221**	**3,992**	**13,490**	**11,428**	**10,500**
Compensation - Average Yearly Incentive Pay						
Management	NIL	NIL	NIL	NIL	NIL	NIL
Non-Union	NIL	NIL	NIL	NIL	NIL	NIL
Union	NIL	NIL	NIL	NIL	NIL	NIL
Total	**NIL**	**NIL**	**NIL**	**NIL**	**NIL**	**NIL**
Compensation - Average Yearly Benefits						
Management	8,726	10,097	9,983	10,935	11,370	11,436
Non-Union	7,691	8,125	8,344	7,830	8,144	8,199
Union	8,421	8,969	9,229	10,122	9,811	9,742
Total	**24,838**	**27,191**	**27,556**	**28,888**	**29,325**	**29,376**
Total Compensation	**1,567,140**	**1,670,800**	**1,640,480**	**1,790,075**	**1,881,287**	**2,021,673**
Charged to OM&A	*1,222,370*	*1,303,224*	*1,279,574*	*1,387,528*	*1,549,717*	*1,656,920*
Charged to Capital Projects	*166,117*	*192,142*	*180,453*	*217,489*	*188,114*	*226,444*
Charged to Miscellaneous Revenues	*178,654*	*175,434*	*180,453*	*185,057*	*143,456*	*138,309*

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocations

SHARED SERVICES & CORPORATE COST ALLOCATIONS

Attachment 1 provides information regarding transactions between ORPC and its affiliate, Ottawa River Energy Solutions Inc. ("ORES"). The agreement governing these transactions appears at Exhibit 1, Tab 2, Schedule 4, Attachment 1.

With the exception of the management charge, all work completed for ORES is tracked through the ORPC project and job costing system. ORES is then invoiced for all work completed on a monthly basis, based on fully allocated cost.

Charges from ORES for meter reading are invoiced to ORPC, with ORPC verifying each reading. The internet charge is a monthly charge. In accordance with section 2.3.2.1 of the Affiliate Relationships Code ("ARC")[1], no business case was required as the annual amount charged for services was below the $100,000 threshold. In accordance with sections 2.3.3 and 2.3.4 of the ARC, pricing for all services is either cost-based or market based, with the Management charge being a fully allocated cost. Any difference in the attachment between the 'Price' and 'Cost' for a service with cost-based pricing represents a return on capital, thus ensuring that fully allocated costs are recovered.

The attachment does not include financial assistance (loans) from ORPC to ORES. In accordance with section 2.4.1 of the ARC, the amount of this financial assistance never exceeds 25% of ORPC's total equity. Loans are made on market terms including interest, in accordance with ARC requirements.

As stated in Exhibit 1, Tab 2, Schedule 4, the affiliate ORES has its own Board of Directors. No costs of either board are allocated to the other company.

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[1] Ontario Energy Board, Affiliate Relationships Code for Electricity Distributors and Transmitters, revised March 15, 2010

Corporate Cost Allocation Tables

Year: 2006

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)
ORES	ORPC	Meter Reading	Cost	88,555	
ORES	ORPC	Internet Service	Market	18,080	
ORPC	ORES	Sentinel Lights	Cost	7,454	6,482
ORPC	ORES	Water Heaters Maint	Cost	16,116	14,014
ORPC	ORES	Administration	Cost	35,615	30,969
ORPC	ORES	Telecommunications	Cost	18,810	16,356

Corporate Cost Allocation Tables

Year: 2007

Name of Company		Service	Pricing	Price for the	Cost for the
From	To	Offered	Methodology	Service ($)	Service ($)
ORES	ORPC	Meter Reading	Cost	88,891	
ORES	ORPC	Internet Service	Market	19,200	
ORPC	ORES	Sentinel Lights	Cost	7,887	6,858
ORPC	ORES	Water Heaters Maint	Cost	14,472	12,584
ORPC	ORES	Administration	Cost	31,231	27,157
ORPC	ORES	Telecommunications	Cost	23,871	20,758

Corporate Cost Allocation Tables

Year: 2008

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)
From	To				
ORES	ORPC	Meter Reading	Cost	88,555	
ORES	ORPC	Internet Service	Market	18,080	
ORPC	ORES	Sentinel Lights	Cost	7,454	6,482
ORPC	ORES	Water Heaters Maint	Cost	16,116	14,014
ORPC	ORES	Administration	Cost	35,615	30,969
ORPC	ORES	Telecommunications	Cost	18,810	16,356

Corporate Cost Allocation Tables

Year: 2009

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)
From	To				
ORES	ORPC	Meter Reading	Cost	33,167	
ORES	ORPC	Internet Service	Market	19,200	
ORPC	ORES	Sentinel Lights	Cost	8,647	7,519
ORPC	ORES	Water Heaters Maint	Cost	21,047	18,302
ORPC	ORES	Management Services	Cost	41,736	36,292
ORPC	ORES	Telecommunications	Cost	23,963	20,837

Corporate Cost Allocation Tables

Year: 2010

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)
From	To				
ORES	ORPC	Internet Service	Market	19,200	
ORPC	ORES	Sentinel Lights	Cost	8,900	7,739
ORPC	ORES	Water Heaters Maint	Cost	25,000	21,739
ORPC	ORES	Management Services	Cost	45,000	39,130
ORPC	ORES	Telecommunications	Cost	15,000	13,043

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

ORPC purchases supplies and services from third parties in order to distribute electricity to its customers. Attachment 1 lists ORPC's expenditures on purchased products and services in 2008 and 2007 in excess of $15,000 from any single supplier. While spending projections are not prepared on this basis, ORPC expects its pattern of expenditures to remain generally consistent with recent history, except for material variances in expenses for Operations, Maintenance and Administration (see Exhibit 4, Tab 3, Schedule 1) and planned capital projects (see Exhibit 2, Tab 4, Schedule 3).

ORPC's procurement policy appears as Attachment 2 to this schedule. ORPC purchases equipment, materials and services in a cost effective manner with full consideration give to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of services. Vendors are screened to ensure knowledge, reputation, and the capability to meet ORPC's needs. The procurement of goods and services for ORPC is carried out with the highest of ethical standards and consideration to the public nature of the expenditures.

Purchase Authorization

ORPC uses a purchase order system to purchase materials and equipment. Major purchases are acquired through a tender process, while purchases of lesser values are purchased using a quotation system. ORPC's Board of Directors approves the capital and operating budgets annually, while the utility's President approves all actual purchases. ORPC's Board must also approve any unbudgeted expenditures in excess of $10,000 prior to purchase, and completes periodic reviews of all spending.

Table of Purchases by Supplier

	2008	2007	Activity	Price By
HYDRO ONE NETWORKS INC	$ 12,367,255.29	$ 12,417,846.25	Commodity	regulated
BROOKFIELD RENEWABLE POWER	$ 2,738,021.30	$ 2,158,005.93	Commodity	regulated
MISSISSIPPI RIVER POWER CORP	Table of Purchases	$ 498,409.58	Commodity	regulated
HARRIS COMPUTER SYSTEMS	$ 245,639.59	$ 52,668.00	Customer Information System	RFP
MEARIE MANAGEMENT INC.	$ 202,077.83	$ 163,787.63	Employee Benefits	market price
OMERS	$ 193,317.76	$ 186,474.34	Employee Pension Plan	sole source
Posi-Plus	$ 192,192.16	$ 75,801.82	Truck Purchase	RFQ
ELSTER CANADIAN METER	$ 113,169.00	$ 94,564.14	Meters	RFQ
WESTBURNE RUDDY ELECTRIC	$ 114,460.40	$ 166,604.68	Electrical Components	market price
H D SUPPLY UTILITIES	$ 95,358.04	$ 162,229.11	Electrical Components	market price
ONT ELECTRICITY FINANCIAL CORP	$ 66,987.02	$ 74,860.41	Commodity-contract with Enerdu	regulated
POSTAGE BY PHONE	$ 47,250.00	$ 47,700.00	Postage	sole source
JOHNSTON & MACKIE LTD	$ 42,975.36	$ 42,820.92	Property Insurance	market price
LAKEPORT POWER	$ 38,439.28		Transformers	market price
A.F. WHITE		$ 36,483.08	Station Transformer Maintenance	market price
SCOTT ROSIEN & DEMPSEY	$ 35,752.50	$ 29,998.00	Auditors	market price
HYDRO ONE-ACCOUNTS RECEIVABLE	$ 32,967.40	$ 11,130.00	Load Transfers	sole source
MEARIE MANAGEMENT INC.	$ 32,206.92	$ 36,027.78	Liability & Vehicle Insurance	market price
ONT. ELECTRICITY FINANCIAL CORP.	$ 21,920.92	$ 21,763.94	Paymt in Lieu of Property Tax	regulated
ONTARIO ENERGY BOARD	$ 27,120.85	$ 28,978.42	Regulator	regulated
TENET COMPUTER SERVICES	$ 27,083.79		Server-Customer Info System	market price
ELECTRICITY DISTRIBUTORS ASCO.	$ 26,250.00	$ 26,341.00	Membership Dues	sole source
TCG COMPUTER SOLUTIONS	$ 24,475.95		Server-Customer Info System	market price
HUGO G. TERMARSCH & SON	$ 23,705.74	$ 20,452.80	Fleet Fuel	market price
LAPOINTE BROS. CHRYSLER PLYMOU	$ 23,068.56		Vehicle Purchase	RFQ
1692378 ONTARIO INC	$ 20,651.88	$ 20,763.28	Roof Repair	RFQ
BELL CANADA C/O SPECIAL BILLING	$ 17,859.65		Joint Use of Poles	sole source
GUELPH UTILITY POLE COMPANY	$ 17,686.76	$ 45,545.28	Poles	market price
BUSINESS TECHNOLOGY SOLUTIONS		$ 16,326.10	Accounting Software Upgrade	market price
WORKPLACE SAFETY & INSUR. BD	$ 15,850.46	$ 13,175.47	Payroll Tax	regulated

Attachment 2 (of 2):

Procurement Policy

Purchasing Policy

Aim

To provide fairness to suppliers and assure value to ORPC customers in the purchasing of goods and services.

More specifically the procurement of goods and services will be based on:

1. Overall price impact for ORPC
2. Quality of goods
3. Reputation and performance of supplier
4. Delivery
5. Environmental impact
6. Safety record of contractors
7. Preference to support local suppliers, based on (in order) suppliers who are customers of ORPC, local suppliers, provincial suppliers, national suppliers
8. Standardization of equipment
9. Impact on the on going work process

Guidelines

Authorization

The authorization level for purchasing for goods and services that have been approved in the capital and operating budget is as follows:

Less than $200	
$200 to $20,000	Supervisors
>$20,000	President or Delegate

For goods and services not approved in the capital or operating budgets:

Less than $10,000	President or Delegate
>$10,000	Board

Process

Normally the requirements will follow the following routines:

RFP (Request for Proposal)	To be issued for goods or services that are being considered for purchase that are not well defined and are of higher value. RFP may be followed up using a tender process or a purchase decision may be made based on the RFP	
Tender	Formal tender process for goods and services >$20,000 or items of complex nature that require well defined specifications and terms and conditions. Fixed closing date/time and official opening by two staff required.	

Quotation	Fax, e-mail or telephone quotations >$200	
Single Source	-For emergency work or sole source vendor work/goods should be limited to the minimum amount to respond to the emergency -For goods and services <$1000	
Cash	<$200	

Evaluation of Bids

Criteria for evaluation of tenders should be included within the request for tender /quotation whenever possible. Evaluation criteria such as reputation, performance record, etc are more subjective and should be weighed in view of the risk to the utility and the need to encourage/developer the supplier pool.

Construction Contractors

Acquiring services from construction contractors needs special attention due to the contractual obligations under the OH&S Act. The Quotation/Tender process has to provide adequate assurance that the contractor has the skills and competence for the work to be performed and they have an acceptable H&S Program in place.

The Electrical Contractors Association of Ontario, EDA and E&USA have prepared a booklet entitled Utilities Tendering Guide 2000 that should be consulted when preparing a tender for construction services.

Service Provider

ORPC has a number of service contracts that are integral to the operation of the utility. While it is possible to re-tender these contracts on a regular basis changing of suppliers would be disruptive to the operation of the utility. These services will be reviewed on ongoing basis to assure that value is received and ORPC continues to receive competitive pricing.

The service contracts as of November 2005 are as follows:

Service	Supplier	Review Period
Meter Reading	ORES	Annual
Auditing	Scott Rosien and Dempsey	4 Years
Banking Services	Bank of Nova Scotia	4 Years
Building Cleaning	Don Peever	
Telephone Answering	Northern Communication	
Water Tank Maintenance	Hans Plumbing	

Supplier Alliances

Agreements may be established with key supplies to form an alliance whereby benefits flow to both parties than can include: reduced inventory levels, improved service levels, etc. Vendor alliances should be reviewed on an annual basis to assure that ORPC is receiving value from the arrangement.

Attachments

1. Request for Proposal
2. Invitation to Tender
3. Letter to Unsuccessful Bidder
4. Contractor Tender Information Requirements
5. Request for Quotation Standard Wording
6. Quotation/Tender Summary Sheet
7. Standard Terms and Conditions

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

ORPC's depreciation policy is described in Exhibit 2, Tab 2, Schedule 3.

Attachment 1 shows the calculation of annual depreciation expense with the half-year rule applied for rate-setting purposes, in accordance with the form prescribed in the Board' filing requirements.[1] These expense amounts were used throughout Exhibit 2, in determining the net fixed asset values included in the rate base.

Depreciation on vehicles and tools is fully burdened to capital and operating expenses. Accordingly, the annual depreciation expense is net of the amortization amounts calculated for these two asset categories.

[1] Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009, Appendix 2-N

Depreciation Expenses

	2005						
	Opening Balance (a)	**Less Fully Depreciated** (b)	**Net for Depreciation** (c) = (a) - (b)	**Net Additions** (d)	**Total for Depreciation** (e) = (c) + 0.5(d)	**Years** (f)	**Depreciation Expense** (g) = (e) / (f)
1805-Land	130,499		130,499	0	130,499	0.00	0
1806-Land Rights	10,809	1,640	9,169		9,169	30.00	306
1808-Buildings and Fixtures	343,114	0	343,114	29,600	357,914	46.13	7,759
Building - Brick, Stone	*327,865*		*327,865*	*0*	*327,865*	*50.00*	*6,557*
Building - other	*15,248*		*15,248*	*29,600*	*30,048*	*25.00*	*1,202*
1810-Leasehold Improvements	28,815	0	28,815		28,815	25.00	*1,153*
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,030,019	778,760	1,251,260	11,901	1,257,210	30.00	41,907
1830-Poles, Towers and Fixtures	7,534,559	737,848	6,796,711	78,045	6,835,734	25.00	273,429
1835-Overhead Conductors and Devices	1,252,569	0	1,252,569	295,278	1,400,208	25.00	56,008
1840-Underground Conduit	2,881,886	215,814	2,666,072	35,141	2,683,643	25.00	107,346
1845-Underground Conductors and Devices	98,824		98,824	67,064	132,356	25.00	5,294
1850-Line Transformers	2,626,770	119,257	2,507,513	159,722	2,587,374	25.00	103,495
1855-Services	308,665	0	308,665	104,615	360,972	25.00	14,439
1860-Meters	829,299	60,254	769,045	19,033	778,562	25.00	31,142
1915-Office Furniture and Equipment	130,462	100,390	30,072	0	30,072	10.00	3,007
1920-Computer Equipment - Hardware	223,222	176,099	47,123	14,401	54,324	5.00	10,865
1925-Computer Software	67,324	17,058	50,266	39,074	69,803	3.00	23,268
1930-Transportation Equipment	1,475,359	1,008,178	467,180	3,023	468,692	7.11	65,920
Automobiles	*50,526*	*23,485*	27,042		27,042	*4.00*	6,760
Trucks under 3 tonnes	*94,731*	*42,015*	52,717		52,717	*5.00*	10,543
Trucks 3 tonnes and over	*1,330,101*	*942,679*	387,422	*3,023*	388,934	*8.00*	48,617
1935-Stores Equipment	1,761	377	1,384	0	1,384	10.00	138
1940-Tools, Shop and Garage Equipment	211,540	127,544	83,996	11,005	89,499	10.00	8,950
1955-Communication Equipment	27,043	17,934	9,109	647	9,432	5.00	1,886
1970-Load Management Controls - Customer Premises	254,912	101,798	153,114	0	153,114	10.00	15,311
1975-Load Management Controls - Utility Premises	64,873	64,873	0	0	0	10.00	0
1980-System Supervisory Equipment	496,993	8,100	488,893	1,543	489,665	14.22	34,437
Equipment	*438,185*		*438,185*		*438,185*	*15.00*	*29,212*
Hardware	*50,708*		*50,708*		*50,708*	*10.00*	*5,071*
Software	*8,100*	*8,100*	*0*	*1,543*	*771*	*5.00*	*154*
1995-Contributions and Grants - Credit	-526,411		-526,411	-188,302	-620,562	25.00	-24,822
TOTAL	**20,502,906**	**3,535,924**	**16,966,982**	**681,792**	**17,307,878**	**22.15**	**781,240**
Vehicles & Tools burdened to jobs							*-74,870*
NET EXPENSE							**706,369**

Depreciation Expenses

	2006						
	Opening Balance (a)	**Less Fully Depreciated** (b)	**Net for Depreciation** (c) = (a) - (b)	**Net Additions** (d)	**Total for Depreciation** (e) = (c) + 0.5(d)	**Years** (f)	**Depreciation Expense** (g) = (e) / (f)
1805-Land	130,499		130,499		130,499	0.00	0
1806-Land Rights	10,809	1,640	9,169		9,169	30.00	306
1808-Buildings and Fixtures	372,713	0	372,713	0	372,713	44.63	8,351
Building - Brick, Stone	*327,865*		*327,865*		*327,865*	*50.00*	*6,557*
Building - other	*44,848*		*44,848*		*44,848*	*25.00*	*1,794*
1810-Leasehold Improvements	28,815		28,815		28,815	*25.00*	1,153
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,041,921	788,390	1,253,531	12,074	1,259,568	30.00	41,986
1830-Poles, Towers and Fixtures	7,612,604	937,698	6,674,906	210,549	6,780,180	25.00	271,207
1835-Overhead Conductors and Devices	1,547,847		1,547,847	219,267	1,657,480	25.00	66,299
1840-Underground Conduit	2,917,028	215,814	2,701,214	16,481	2,709,454	25.00	108,378
1845-Underground Conductors and Devices	165,888		165,888	38,961	185,368	25.00	7,415
1850-Line Transformers	2,786,492	119,257	2,667,235	57,171	2,695,821	25.00	107,833
1855-Services	413,280		413,280	100,441	463,501	25.00	18,540
1860-Meters	848,332	60,254	788,078	14,252	795,204	25.00	31,808
1915-Office Furniture and Equipment	130,462	101,382	29,080	-7,687	25,236	10.00	2,524
1920-Computer Equipment - Hardware	237,623	176,099	61,524	7,966	65,507	5.00	13,101
1925-Computer Software	106,399	39,765	66,633	38,159	85,712	3.00	28,571
1930-Transportation Equipment	1,478,382	1,074,231	404,150	26,605	417,453	7.09	58,861
Automobiles	*50,526*	*23,485*	*27,042*	*4,506*	*29,294*	*4.00*	*7,324*
Trucks under 3 tonnes	*94,731*	*54,493*	*40,238*		*40,238*	*5.00*	*8,048*
Trucks 3 tonnes and over	*1,333,124*	*996,253*	*336,871*	*22,100*	*347,920*	*8.00*	*43,490*
1935-Stores Equipment	1,761	377	1,384		1,384	10.00	138
1940-Tools, Shop and Garage Equipment	222,546	142,560	79,986	9,409	84,690	10.00	8,469
1955-Communication Equipment	27,690	17,934	9,756	1,854	10,683	5.00	2,137
1970-Load Management Controls - Customer Premises	254,912	189,475	65,437		65,437	10.00	6,544
1975-Load Management Controls - Utility Premises	64,873	64,873	0		0	10.00	0
1980-System Supervisory Equipment	498,536	8,100	490,436	0	490,436	14.18	34,592
Equipment	*438,185*		*438,185*		*438,185*	*15.00*	*29,212*
Hardware	*50,708*		*50,708*		*50,708*	*10.00*	*5,071*
Software	*9,643*	*8,100*	*1,543*		*1,543*	*5.00*	*309*
1995-Contributions and Grants - Credit	-714,713		-714,713	-200,343	-814,884	25.00	-32,595
TOTAL	**21,184,698**	**3,937,850**	**17,246,848**	**545,160**	**17,519,428**	**22.30**	**785,617**
Vehicles & Tools burdened to jobs							*-67,330*
NET EXPENSE							**718,286**

Depreciation Expenses

	2007						
	Opening Balance (a)	**Less Fully Depreciated** (b)	**Net for Depreciation** (c) = (a) - (b)	**Net Additions** (d)	**Total for Depreciation** (e) = (c) + 0.5(d)	**Years** (f)	**Depreciation Expense** (g) = (e) / (f)
1805-Land	130,499		130,499		130,499	0.00	0
1806-Land Rights	10,809	1,640	9,169		9,169	30.00	306
1808-Buildings and Fixtures	372,713	0	372,713	0	372,713	44.63	8,351
Building - Brick, Stone	*327,865*		*327,865*		*327,865*	*50.00*	*6,557*
Building - other	*44,848*		*44,848*		*44,848*	*25.00*	*1,794*
1810-Leasehold Improvements	28,815		28,815	19,588	*38,609*	*25.00*	*1,544*
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,053,995	788,390	1,265,605	18,175	1,274,692	30.00	42,490
1830-Poles, Towers and Fixtures	7,823,153	1,184,027	6,639,126	117,646	6,697,949	25.00	267,918
1835-Overhead Conductors and Devices	1,767,114		1,767,114	247,669	1,890,948	25.00	75,638
1840-Underground Conduit	2,933,508	215,814	2,717,695		2,717,695	25.00	108,708
1845-Underground Conductors and Devices	204,849		204,849	42,993	226,346	25.00	9,054
1850-Line Transformers	2,843,663	130,832	2,712,831	177,265	2,801,464	25.00	112,059
1855-Services	513,721		513,721	114,212	570,828	25.00	22,833
1860-Meters	862,584	65,409	797,175	-73	797,138	25.00	31,886
1915-Office Furniture and Equipment	122,775	101,472	21,303		21,303	10.00	2,130
1920-Computer Equipment - Hardware	245,589	176,099	69,490	5,497	72,239	5.00	14,448
1925-Computer Software	144,557	56,369	88,188	16,211	96,294	3.00	32,098
1930-Transportation Equipment	1,504,987	1,184,545	320,442	81,506	361,195	6.89	52,426
Automobiles	*72,626*	*23,485*	*49,141*		*49,141*	*4.00*	*12,285*
Trucks under 3 tonnes	*94,731*	*79,605*	*15,127*		*15,127*	*5.00*	*3,025*
Trucks 3 tonnes and over	*1,337,630*	*1,081,456*	*256,174*	*81,506*	*296,927*	*8.00*	*37,116*
1935-Stores Equipment	1,761	377	1,384		1,384	10.00	138
1940-Tools, Shop and Garage Equipment	231,955	142,560	89,395	2,274	90,532	10.00	9,053
1955-Communication Equipment	29,544	29,296	248		248	5.00	50
1970-Load Management Controls - Customer Premises	254,912	211,009	43,903		43,903	10.00	4,390
1975-Load Management Controls - Utility Premises	64,873	64,873	0		0	10.00	0
1980-System Supervisory Equipment	498,536	105,572	392,964	0	392,964	0.00	0
Equipment	*438,185*	*97,472*				*15.00*	
Hardware	*50,708*					*10.00*	
Software	*9,643*	*8,100*				*5.00*	
1995-Contributions and Grants - Credit	-915,056		-915,056	-50,096	-940,104	25.00	-37,604
TOTAL	**21,729,858**	**4,458,284**	**17,271,574**	**792,866**	**17,668,007**	**23.31**	**757,915**
Vehicles & Tools burdened to jobs							*-61,480*
NET EXPENSE							**696,436**

Depreciation Expenses

	2008						
	Opening Balance (a)	**Less Fully Depreciated** (b)	**Net for Depreciation** (c) = (a) - (b)	**Net Additions** (d)	**Total for Depreciation** (e) = (c) + 0.5(d)	**Years** (f)	**Depreciation Expense** (g) = (e) / (f)
1805-Land	130,499		130,499		130,499	0.00	0
1806-Land Rights	10,809	1,640	9,169		9,169	30.00	306
1808-Buildings and Fixtures	372,713	0	372,713	24,793	385,110	44.85	8,586
Building - Brick, Stone	*327,865*		*327,865*	*26,104*	*340,917*	*50.00*	*6,818*
Building - other	*44,848*		*44,848*	*-1,311*	*44,193*	*25.00*	*1,768*
1810-Leasehold Improvements	48,403		48,403	1,311	49,059	25.00	1,962
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,072,169	788,390	1,283,779	12,288	1,289,923	30.00	42,997
1830-Poles, Towers and Fixtures	7,940,798	1,478,337	6,462,461	88,870	6,506,896	25.00	260,276
1835-Overhead Conductors and Devices	2,014,783		2,014,783	202,916	2,116,241	25.00	84,650
1840-Underground Conduit	2,933,508	215,814	2,717,695		2,717,695	25.00	108,708
1845-Underground Conductors and Devices	247,842		247,842	4,814	250,249	25.00	10,010
1850-Line Transformers	3,020,928	134,214	2,886,714	59,677	2,916,553	25.00	116,662
1855-Services	627,934		627,934	120,154	688,011	25.00	27,520
1860-Meters	862,511	65,409	797,102	11,409	802,806	25.00	32,112
1915-Office Furniture and Equipment	122,775	101,472	21,303		21,303	10.00	2,130
1920-Computer Equipment - Hardware	251,086	237,623	13,463	61,500	44,214	5.00	8,843
1925-Computer Software	160,768	86,862	73,907	289,259	218,536	3.00	72,845
1930-Transportation Equipment	1,586,493	1,234,767	351,726	-6,797	348,328	7.37	47,234
Automobiles	*72,626*	*50,526*	*22,100*		*22,100*	*4.00*	*5,525*
Trucks under 3 tonnes	*94,731*	*93,485*	*1,247*	*22,319*	*12,406*	*5.00*	*2,481*
Trucks 3 tonnes and over	*1,419,136*	*1,090,756*	*328,380*	*-29,116*	*313,822*	*8.00*	*39,228*
1935-Stores Equipment	1,761	1,761	0		0	10.00	0
1940-Tools, Shop and Garage Equipment	234,229	165,196	69,033		69,033	10.00	6,903
1955-Communication Equipment	29,544	29,544	0		0	5.00	0
1970-Load Management Controls - Customer Premises	254,912	233,570	21,342		21,342	10.00	2,134
1975-Load Management Controls - Utility Premises	64,873	64,873	0		0	10.00	0
1980-System Supervisory Equipment	498,536	242,852	255,684	0	255,684	13.50	18,942
Equipment	*438,185*	*234,752*	*203,433*		*203,433*	*15.00*	*13,562*
Hardware	*50,708*		*50,708*		*50,708*	*10.00*	*5,071*
Software	*9,643*	*8,100*	*1,543*		*1,543*	*5.00*	*309*
1995-Contributions and Grants - Credit	-965,152		-965,152	-194,103	-1,062,204	25.00	-42,488
TOTAL	**22,522,724**	**5,082,324**	**17,440,400**	**676,090**	**17,778,445**	**21.94**	**810,333**
Vehicles & Tools burdened to jobs							*-54,137*
NET EXPENSE							**756,196**

Depreciation Expenses

	2009						
	Opening Balance (a)	**Less Fully Depreciated** (b)	**Net for Depreciation** (c) = (a) - (b)	**Net Additions** (d)	**Total for Depreciation** (e) = (c) + 0.5(d)	**Years** (f)	**Depreciation Expense** (g) = (e) / (f)
1805-Land	130,499		130,499		130,499	0.00	0
1806-Land Rights	10,809	1,640	9,169		9,169	30.00	306
1808-Buildings and Fixtures	397,506	0	397,506	6,329	400,671	44.78	8,947
Building - Brick, Stone	*353,969*		*353,969*		*353,969*	*50.00*	*7,079*
Building - other	*43,537*		*43,537*	*6,329*	*46,702*	*25.00*	*1,868*
1810-Leasehold Improvements	49,714		49,714		49,714	25.00	1,989
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,084,457	1,007,810	1,076,647	478,615	1,315,955	30.00	43,865
1830-Poles, Towers and Fixtures	8,029,668	1,773,746	6,255,922	78,052	6,294,948	25.00	251,798
1835-Overhead Conductors and Devices	2,217,699		2,217,699	213,146	2,324,272	25.00	92,971
1840-Underground Conduit	2,933,508	215,814	2,717,695		2,717,695	25.00	108,708
1845-Underground Conductors and Devices	252,656		252,656	77,683	291,497	25.00	11,660
1850-Line Transformers	3,080,605	202,558	2,878,047	119,746	2,937,920	25.00	117,517
1855-Services	748,088		748,088	127,263	811,719	25.00	32,469
1860-Meters	873,920	299,357	574,563	2,847	575,986	25.00	23,039
1915-Office Furniture and Equipment	122,775	101,472	21,303		21,303	10.00	2,130
1920-Computer Equipment - Hardware	312,587	245,589	66,998	7,424	70,709	5.00	14,142
1925-Computer Software	450,027	125,478	324,550	4,202	326,650	3.00	108,883
1930-Transportation Equipment	1,579,695	1,262,781	316,914	14,240	324,034	7.13	45,468
Automobiles	*72,626*	*50,526*	*22,100*		*22,100*	*4.00*	*5,525*
Trucks under 3 tonnes	*117,050*	*94,822*	*22,228*	*14,240*	*29,347*	*5.00*	*5,869*
Trucks 3 tonnes and over	*1,390,020*	*1,117,433*	*272,587*		*272,587*	*8.00*	*34,073*
1935-Stores Equipment	1,761	1,761	0		0	10.00	0
1940-Tools, Shop and Garage Equipment	234,229	167,928	66,301		66,301	10.00	6,630
1955-Communication Equipment	29,544	29,544	0		0	5.00	0
1970-Load Management Controls - Customer Premises	254,912	246,519	8,394		8,394	10.00	839
1975-Load Management Controls - Utility Premises	64,873	64,873	0		0	10.00	0
1980-System Supervisory Equipment	498,536	259,565	238,971	3,732	240,837	13.37	18,014
Equipment	*438,185*	*251,465*	*186,720*		*186,720*	*15.00*	*12,448*
Hardware	*50,708*		*50,708*	*3,732*	*52,574*	*10.00*	*5,257*
Software	*9,643*	*8,100*	*1,543*		*1,543*	*5.00*	*309*
1995-Contributions and Grants - Credit	-1,159,255		-1,159,255	-119,236	-1,218,873	25.00	-48,755
TOTAL	**23,198,813**	**6,006,435**	**17,192,379**	**1,014,042**	**17,699,399**	**21.06**	**840,620**
Vehicles & Tools burdened to jobs							*-52,098*
NET EXPENSE							**788,522**

Depreciation Expenses

	2010						
	Opening Balance (a)	**Less Fully Depreciated** (b)	**Net for Depreciation** (c) = (a) - (b)	**Net Additions** (d)	**Total for Depreciation** (e) = (c) + 0.5(d)	**Years** (f)	**Depreciation Expense** (g) = (e) / (f)
1805-Land	130,499		130,499	24,000	142,499	0.00	0
1806-Land Rights	10,809	1,640	9,169		9,169	30.00	306
1808-Buildings and Fixtures	403,836	0	403,836	60,000	433,836	44.85	9,674
Building - Brick, Stone	*353,969*		*353,969*	*60,000*	*383,969*	*50.00*	*7,679*
Building - other	*49,866*		*49,866*		*49,866*	*25.00*	*1,995*
1810-Leasehold Improvements	49,714		49,714		49,714	25.00	1,989
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,563,072	1,013,631	1,549,441	150,000	1,624,441	30.00	54,148
1830-Poles, Towers and Fixtures	8,107,720	2,125,830	5,981,890	103,470	6,033,625	25.00	241,345
1835-Overhead Conductors and Devices	2,430,844	102,864	2,327,980	80,490	2,368,225	25.00	94,729
1840-Underground Conduit	2,933,508	215,814	2,717,695	51,000	2,743,195	25.00	109,728
1845-Underground Conductors and Devices	330,339		330,339	82,350	371,514	25.00	14,861
1850-Line Transformers	3,200,352	265,787	2,934,565	179,420	3,024,275	25.00	120,971
1855-Services	875,350		875,350	87,200	918,950	25.00	36,758
1860-Meters	876,767	299,357	577,410	24,000	589,410	25.00	23,576
1915-Office Furniture and Equipment	122,775	105,012	17,763	8,000	21,763	10.00	2,176
1920-Computer Equipment - Hardware	320,010	252,510	67,500	6,000	70,500	5.00	14,100
1925-Computer Software	454,229	152,663	301,566	18,700	310,916	3.00	103,639
1930-Transportation Equipment	1,593,935	1,262,781	331,154	133,143	397,725	6.26	63,535
Automobiles	*72,626*	*50,526*	*22,100*	*133,143*	*88,671*	*4.00*	*22,168*
Trucks under 3 tonnes	*131,290*	*94,822*	*36,468*		*36,468*	*5.00*	*7,294*
Trucks 3 tonnes and over	*1,390,020*	*1,117,433*	*272,587*		*272,587*	*8.00*	*34,073*
1935-Stores Equipment	1,761	1,761	0		0	10.00	0
1940-Tools, Shop and Garage Equipment	234,229	167,928	66,301	10,000	71,301	10.00	7,130
1955-Communication Equipment	29,544	29,544	0	3,700	1,850	5.00	370
1970-Load Management Controls - Customer Premises	254,912	246,519	8,394		8,394	10.00	839
1975-Load Management Controls - Utility Premises	64,873	64,873	0		0	10.00	0
1980-System Supervisory Equipment	502,268	310,273	191,995	80,000	231,995	14.69	15,796
Equipment	*438,185*	*251,465*	*186,720*	*80,000*	*226,720*	*15.00*	*15,115*
Hardware	*54,440*	*50,708*	*3,732*		*3,732*	*10.00*	*373*
Software	*9,643*	*8,100*	*1,543*		*1,543*	*5.00*	*309*
1995-Contributions and Grants - Credit	-1,278,491		-1,278,491	-103,000	-1,329,991	25.00	-53,200
TOTAL	**24,212,855**	**6,618,787**	**17,594,069**	**998,473**	**18,093,305**	**20.98**	**862,470**
Vehicles & Tools burdened to jobs							*-70,665*
NET EXPENSE							**791,805**

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

ORPC is subject to the PILs regime, and therefore remits payments in lieu of corporate taxes to the Ontario Energy Financial Corporation, to be applied again the stranded debt of the former Ontario Hydro.

ORPC files Federal and Provincial tax returns annually. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable.

There are no non-utility activities included in ORPC’s financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

There are no outstanding audits, reassessments or disputes relating the tax returns filed by ORPC.

Schedule 2 of this tab addresses the PILs allowance previously approved by the Board and the actual expenses for PILs. Schedule 3 presents the allowance for PILs to be included in the proposed revenue requirement for the 2010 test year.

HISTORICAL PILS

Attachment 1 presents the model used to derive the allowance for the Provision In Lieu of Taxes ("PILs") included in ORPC's 2006 Board-approved revenue requirement. Attachments 2 and 3 show the latest returns filed in 2008 by the utility for Federal and Ontario income taxes, respectively,

Actual PILs expense in 2006 exceeded the Board-approved amount, due to lower distribution expenses and higher miscellaneous revenues which increased taxable income. PILs expense declined from 2006 to 2009: expenses grew more than revenues, as a result taxable income decreased during this period. Income tax rates declined during this time, also leading to lower PILs expense.

Attachment 1 (of 3):

Previously Approved PILs Model

Sheet Index:

Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility:	**OTTAWA RIVER POWER CORPORATION - Revision 2**
License Number:	**ED-2003-0033**
File Number:	**RP-2005-0020**
	EB-2005-0403
Name of Contact:	**JANE WILKINSON**
Phone Number:	**613-732-3687** **Ext: 34**
E-Mail Address:	**jwilkinson@orpowercorp.com**
Date:	**Friday, April 28, 2006**
Version Number:	**PILS2006.V2.1**

SUMMARY SHEET

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON
Phone Number: 613-732-3687

Ratebase	10,759,535	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	484,179	4-1 DATA for PILS MODEL	F 23
Calculation of Deemed Interest			
Debt Ratio	50.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	7.25%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	390,033		

<u>Questions that must be answered</u>	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	Yes
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	Yes
2. Does the applicant have any Investment Tax Credits (ITC)?	No
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	No
4. Does the applicant have any Capital Gains or Losses for tax purposes?	No
5. Does the applicant have any Capital Leases?	No
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2004 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	No
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2004 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2004 and/or prior years?	No

Tax Rates & Exemptions

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON   Phone Number: 613-732-3687

Applicant	Rate Base	OCT Exemption	LCT Exemption
		10,000,000	50,000,000
OTTAWA RIVER POWER CORPORATIC	10,759,535	10,000,000	50,000,000
Regulated Affiliates (if applicable)			
1		0	0
2		0	0
3		0	0
4		0	0
5		0	0
Total	10,759,535	10,000,000	50,000,000

Corporate Tax Rates for Test Year

Income Range	**0 to 300,000**	**300,000 to 400,000**	**400,000 to 1,128,519**	**>1,128,519**
Federal	13.12%	22.12%	22.12%	22.12%
Ontario	5.50%	5.50%	5.50%	14.00%
Income Tax Rates used to gross up the true up variance	18.62%	27.62%	27.62%	36.12%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.300%
LCT rate	0.125%
Surtax	1.12%

2004 Adjusted Taxable Income

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON
Phone Number: 613-732-3687

	A	B	C	D	E
9		T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
10	**Income before PILs/Taxes**	A	775,183	0	775,183
11	**Additions:**				
12	Interest and penalties on taxes	103	2,168	0	2,168
13	Amortization of tangible assets	104	672,636	0	672,636
14	Amortization of intangible assets	106	0	0	0
15	Recapture of capital cost allowance from Schedule 8	107	0	0	0
16	Gain on sale of eligible capital property from Schedule 10	108	0	0	0
17	Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
18	Loss in equity of subsidiaries and affiliates	110	0	0	0
19	Loss on disposal of assets	111	0	0	0
20	Charitable donations	112	0	0	0
21	Taxable Capital Gains	113	0	0	0
22	Political Donations	114	0	0	0
23	Deferred and prepaid expenses	116	0	0	0
24	Scientific research expenditures deducted on financial statements	118	0	0	0
25	Capitalized interest	119	0	0	0
26	Non-deductible club dues and fees	120	0	0	0
27	Non-deductible meals and entertainment expense	121	0	0	0
28	Non-deductible automobile expenses	122	0	0	0
29	Non-deductible life insurance premiums	123	0	0	0
30	Non-deductible company pension plans	124	0	0	0
31	Tax reserves deducted in prior year	125	112,085	0	112,085
32	Reserves from financial statements- balance at end of year	126	131,846	0	131,846
33	Soft costs on construction and renovation of buildings	127	0	0	0
34	Book loss on joint ventures or partnerships	205	0	0	0
35	Capital items expensed	206	0	0	0
36	Debt issue expense	208	0	0	0
37	Development expenses claimed in current year	212	0	0	0
38	Financing fees deducted in books	216	0	0	0
39	Gain on settlement of debt	220	0	0	0
40	Non-deductible advertising	226	0	0	0
41	Non-deductible interest	227	0	0	0
42	Non-deductible legal and accounting fees	228	0	0	0
43	Recapture of SR&ED expenditures	231	0	0	0
44	Share issue expense	235	0	0	0
45	Write down of capital property	236	0	0	0
46	Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
47	***Other Additions***				
48	Interest Expensed on Capital Leases	290	0	0	0
49	Realized Income from Deferred Credit Accounts	291	0	0	0
50	Pensions	292	0	0	0
51	Non-deductible penalties	293	0	0	0
52		294	0	0	0
53		295	0	0	0
54	**Total Additions**		**918,735**	**0**	**918,735**

2004 Adjusted Taxable Income

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON
Phone Number: 613-732-3687

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
Deductions:				
Gain on disposal of assets per financial statements	401	0	0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	698,099	0	698,099
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	276,779	0	276,779
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves claimed in current year	413	131,846	0	131,846
Reserves from financial statements - balance at beginning of year	414	112,085	0	112,085
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
	393	0	0	0
	394	0	0	0
Total Deductions		**1,218,809**	**0**	**1,218,809**
Net Income for Tax Purposes		**475,109**	**0**	**475,109**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
TAXABLE INCOME		**475,109**	**0**	**475,109**

2004 Schedule 8 and 10 UCC and CEC

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: JANE WILKINSON
Phone Number: 613-732-3687

Methodology: This schedule starts with 2004 Schedules 8 and 10, as filed in the actual 2004 corporate tax returns; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	UCC End of Year Dec 31/04 per tax returns	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System - post 1987	158,162	0	0	158,162
2	Distribution System - pre 1988	7,755,326	0	0	7,755,326
8	General Office/Stores Equip	569,901	0	0	569,901
10	Computer Hardware/ Vehicles	294,243	0	0	294,243
10.1	Certain Automobiles	0	0	0	0
12	Computer Software	0	0	0	0
13_{1}	Lease # 1	0	0	0	0
13_{2}	Lease #2	0	0	0	0
13_{3}	Lease # 3	0	0	0	0
13_{4}	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	3,238	0	0	3,238
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - UCC	**8,780,870**	**0**	**0**	**8,780,870**
CEC	Goodwill	0	0	0	0
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	3,677,204	0	0	3,677,204
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - CEC	**3,677,204**	**0**	**0**	**3,677,204**

UCC Additions and CEC Additions

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0	0	0
1715	Station Equipment	1	0	0	0	0	0	0
1720	Towers and Fixtures	1	0	0	0	0	0	0
1725	Poles and Fixtures	1	0	0	0	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0	0	0	0
1735	Underground Conduit	1	0	0	0	0	0	0
1740	Underground Conductors and Devices	1	0	0	0	0	0	0
1745	Roads and Trails	1	0	0	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0	0	0	0
1825	Storage Battery Equipment	1	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0	0	0	0
1840	Underground Conduit	1	0	0	0	0	0	0
1845	Underground Conductors and Devices	1	0	0	0	0	0	0
1850	Line Transformers	1	0	0	0	0	0	0
1855	Services	1	0	0	0	0	0	0
1860	Meters	1	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0	0	0	0
1908	Buildings and Fixtures	1	0	0	0	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0	0	0	0
xxx2	Smart Meters	1	0	0	0	0	0	0
SUBTOTAL - CLASS 1			**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	2	0	0	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0	0	0
1715	Station Equipment	2	0	0	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0	0	0
1735	Underground Conduit	2	0	0	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0	0	0
1745	Roads and Trails	2	0	0	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0	0	0
1840	Underground Conduit	2	0	0	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0	0	0
1850	Line Transformers	2	0	0	0	0	0	0
1855	Services	2	0	0	0	0	0	0
1860	Meters	2	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1875	Street Lighting and Signal Systems	8	0	0	0	0	0	0
1915	Office Furniture and Equipment	8	0	0	0	0	0	0
1935	Stores Equipment	8	0	0	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0	0	0
1955	Communication Equipment	8	0	0	0	0	0	0
1960	Miscellaneous Equipment	8	0	0	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0	0	0
1980	System Supervisory Equipment	8	0	0	0	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0	0	0
SUBTOTAL - CLASS 8			**0**	**0**	**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0	0	0	0
SUBTOTAL - CLASS 45			**0**	**0**	**0**	**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0	0	0	0
SUBTOTAL - CLASS 10			**0**	**0**	**0**	**0**	**0**	**0**
1925	Computer Software - CL12	12	9,000	0	0	0	9,000	0
SUBTOTAL - CLASS 12			**9,000**	**0**	**0**	**0**	**9,000**	**0**
1630	Leasehold Improvements	13_1	0	0	0	0	0	0
1710	Leasehold Improvements	13_2	0	0	0	0	0	0
1810	Leasehold Improvements	13_3	0	0	0	0	0	0
1910	Leasehold Improvements	13_4	0	0	0	0	0	0
SUBTOTAL - CLASS 13			**0**	**0**	**0**	**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0	0	0
1675	Generators	43.1	0	0	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**	**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0	0	0	0
1616	Land Rights	ECP	0	0	0	0	0	0
1706	Land Rights	ECP	0	0	0	0	0	0
1806	Land Rights	ECP	0	0	0	0	0	0
1906	Land Rights	ECP	0	0	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0	0	0
SUBTOTAL - Eligible Capital Property			**0**	**0**	**0**	**0**	**0**	**0**
1615	Land	LAND	0	0	0	0	0	0
1705	Land	LAND	0	0	0	0	0	0
1805	Land	LAND	0	0	0	0	0	0
1905	Land	LAND	0	0	0	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**	**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0	0	0
			0	0	0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**9,000**	**0**	**0**	**0**	**9,000**	**0**

Schedule 8 CCA Test Year

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	Test Year - Tier 1, Tier 2 Additions	Test Year - Tier 1, Tier 2 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	158,162	0	0	158,162	0	158,162	4%	6,326	151,836
2	Distribution System - pre 1988	7,755,326	0	0	7,755,326	0	7,755,326	6%	465,320	7,290,006
8	General Office/Stores Equip	569,901	0	0	569,901	0	569,901	20%	113,980	455,921
10	Computer Hardware/ Vehicles	294,243	0	0	294,243	0	294,243	30%	88,273	205,970
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	0	9,000	0	9,000	4,500	4,500	100%	4,500	4,500
13_1	Leasehold Improvement # 1	0	0	0	0	0	0	5	0	0
13_2	Leasehold Improvement # 2	0	0	0	0	0	0	4	0	0
13_3	Leasehold Improvement # 3	0	0	0	0	0	0	3	0	0
13_4	Leasehold Improvement # 4	0	0	0	0	0	0	4	0	0
14	Franchise	0	0	0	0	N/A	0	7	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	3,238	0	0	3,238	0	3,238	45%	1,457	1,781
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
			0	0	0	0	0		0	0
			0	0	0	0	0		0	0
		0			0	0	0		0	0
		0			0	0	0		0	0
	TOTAL	**8,780,870**	**9,000**	**0**	**8,789,870**	**4,500**	**8,785,370**		**679,856**	**8,110,014**

Ontario

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: JANE WILKINSON   Phone Number: 613-732-3687

Cumulative Eligible Capital				**3,677,204**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments				
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**3,677,204**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**
Cumulative Eligible Capital Balance				**3,677,204**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")	**3,677,204**	**x 7% =**		**257,404**
Cumulative Eligible Capital - Closing Balance				**3,419,800**

Schedule 13 – Tax Reserves

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: JANE WILKINSON
Phone Number: 613-732-3687

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)	71,846		71,846		71,846			71,846	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves	60,000		60,000		60,000			60,000	0	
			0		0			0	0	
			0		0			0	0	
Total	**131,846**	**0**	**131,846**	**0**	**131,846**	**0**	**0**	**131,846**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)			0		0			0	0	
General reserve for bad debts	71,846		71,846		71,846			71,846	0	
Accrued Employee Future Benefits:	60,000		60,000		60,000			60,000	0	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost			0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**131,846**	**0**	**131,846**	**0**	**131,846**	**0**	**0**	**131,846**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

CONTINUITY OF RESERVES

						Test Year Adjustments				
Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Additions	Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses

Schedule 7-1 Loss Carry-Forwards

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion [1]	Utility Balance
Actual/Estimated December 31, 2004			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion [1]	Utility Balance
Actual/Estimated December 31, 2004			0
Application of Loss Carry Forward to reduce taxable capital gains in 2005			0
Other Adjustments +ADD -(DEDUCT)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year (see Note 2)			0
Balance available for use post Test Year	0	0	0

Note

[1] **Please describe your methodology and rationale in the Manager's Summary**

[2] **Please provide calculation of the net-capital loss utilization and the inclusion rates that you proposes to use in your actual tax returns**

Excess Interest Expense

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Calculated Deemed 2004 Interest Expense in 2006 EDR model	390,033		
2004 Actual Interest Expense	404,974	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2004 Capitalized Interest (USoA 6040)		2-2 UNADJUSTED ACCOUNTING DATA	L 431
2004 Capitalized Interest (USoA 6042)		2-2 UNADJUSTED ACCOUNTING DATA	L 432
2004 Actual Interest	404,974		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	404,974		
Excess Interest Expense for 2006 PILs	14,941		

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2004 and prior years.

Test Year Taxable Income

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		484,179	775,183	-291,004	*Note this value will be significantly larger due to PILs collected in 2004 Adjusted Taxable Income.*
Additions:					
Interest and penalties on taxes	103		2,168	-2,168	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	672,636	672,636	0	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		0	0	
Recapture of capital cost allowance from Schedule 8	107		0	0	
Gain on sale of eligible capital property from Schedule 10	108		0	0	
Income or loss for tax purposes- joint ventures or partnerships	109		0	0	
Loss in equity of subsidiaries and affiliates	110		0	0	
Loss on disposal of assets	111		0	0	
Charitable donations	112		0	0	
Taxable Capital Gains	113		0	0	
Political Donations	114		0	0	
Deferred and prepaid expenses	116		0	0	
Scientific research expenditures deducted on financial statements	118		0	0	
Capitalized interest	119		0	0	
Non-deductible club dues and fees	120		0	0	
Non-deductible meals and entertainment expense	121		0	0	
Non-deductible automobile expenses	122		0	0	
Non-deductible life insurance premiums	123		0	0	
Non-deductible company pension plans	124		0	0	
Tax reserves beginning of year	125	131,846	112,085	19,761	
Reserves from financial statements- balance at end of year	126	131,846	131,846	0	
Soft costs on construction and renovation of buildings	127		0	0	
Book loss on joint ventures or partnerships	205		0	0	
Capital items expensed	206		0	0	
Debt issue expense	208		0	0	
Development expenses claimed in current year	212		0	0	
Financing fees deducted in books	216		0	0	
Gain on settlement of debt	220		0	0	
Non-deductible advertising	226		0	0	
Non-deductible interest	227		0	0	
Non-deductible legal and accounting fees	228		0	0	
Recapture of SR&ED expenditures	231		0	0	
Share issue expense	235		0	0	
Write down of capital property	236		0	0	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0	0	
Other Additions: (please explain in detail the nature of the item)					
Interest Expensed on Capital Leases	290		0	0	
Realized Income from Deferred Credit Accounts	291		0	0	
Pensions	292		0	0	
Non-deductible penalties	293		0	0	
	294		0	0	
	295		0	0	
	296		0	0	
	297		0	0	
Total Additions		**936,328**	**918,735**	**17,593**	

Test Year Taxable Income

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Deductions:					
Gain on disposal of assets per financial statements	401		0	0	
Dividends not taxable under section 83	402		0	0	
Capital cost allowance from Schedule 8	403	679,856	698,099	-18,243	
Terminal loss from Schedule 8	404		0	0	
Cumulative eligible capital deduction from Schedule 10 CEC	405	257,404	276,779	-19,375	
Allowable business investment loss	406		0	0	
Deferred and prepaid expenses	409		0	0	
Scientific research expenses claimed in year	411		0	0	
Tax reserves end of year	413	131,846	131,846	0	
Reserves from financial statements - balance at beginning of year	414	131,846	112,085	19,761	
Contributions to deferred income plans	416		0	0	
Book income of joint venture or partnership	305		0	0	
Equity in income from subsidiary or affiliates	306		0	0	
Other deductions: (Please explain in detail the nature of the item)					
Interest capitalized for accounting deducted for tax	390		0	0	
Capital Lease Payments	391		0	0	
Non-taxable imputed interest income on deferral and variance accounts	392		0	0	
	393		0	0	
	394		0	0	
Excess Interest (from Tab "Schedule 7-3")	395	14,941	0	14,941	Applicable to Test Year only
	396		0	0	
	397		0	0	
Total Deductions		**1,215,893**	**1,218,809**	**-2,916**	
NET INCOME FOR TAX PURPOSES		**204,614**	**475,109**	**-270,495**	
Charitable donations	311		0	0	
Taxable dividends received under section 112 or 113	320		0	0	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0	
Net-capital losses of preceding taxation years (Please show calculation)	332		0	0	
Limited partnership losses of preceding taxation years from Schedule 4	335		0	0	
TAXABLE INCOME (C/F to tab "Tax Provision)		**204,614**	**475,109**	**-270,495**	

Ontario Capital Tax, Large Corporation Tax

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B
Enter the LCT amount from either Section A or B in tab "Tax Provision" cell D28

Section A

	Wires Only
ONTARIO CAPITAL TAX	
Rate Base	10,759,535
Less: Exemption	10,000,000
Deemed Taxable Capital	759,535
Rate in 2006	0.300%
Net Amount (Taxable Capital x Rate)	2,279
FEDERAL LCT	
Rate Base from	10,759,535
Less: Exemption	50,000,000
Deemed Taxable Capital	0
Rate in 2006	0.125%
Gross Amount (Taxable Capital x Rate)	0
Less: Federal Surtax	2,292
Net LCT	0
Grossed-up LCT	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX
(From Ontario CT23)
PAID-UP CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Paid-up capital stock	5,585,838		5,585,838
Retained earnings (if deficit, use negative sign)	2,029,465		2,029,465
Capital and other surplus excluding	6,200,000		6,200,000
appraisal surplus			0
Loans and advances	5,585,838		5,585,838
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits			0
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	19,401,141	0	19,401,141
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	98,236		98,236
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	19,302,905	0	19,302,905

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations	499,071		499,071
Eligible loans and advances to related corporations			0
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	499,071	0	499,071

Ontario Capital Tax, Large Corporation Tax

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON   Phone Number: 613-732-3687

TOTAL ASSETS	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	18,663,567		18,663,567
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	18,663,567	0	18,663,567
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	98,236		98,236
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0
Other adjustments (if deducting, use negative sign)			0
Total Assets	18,565,331	0	18,565,331
Investment Allowance	499,071	0	499,071
Taxable Capital			
Net paid-up capital	19,302,905	0	19,302,905
Investment Allowance	499,071	0	499,071
Taxable Capital	18,803,834	0	18,803,834
Capital Tax Calculation			
Deduction from taxable capital up to $10,000,000	10,000,000		10,000,000
Net Taxable Capital			8,803,834
Rate			0.3000%
Ontario Capital Tax (Deductible, not grossed-up)			26,412

Ontario Capital Tax, Large Corporation Tax

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

Ontario Capital Tax, Large Corporation Tax

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

LARGE CORPORATION TAX
(From Federal Schedule 33)

CAPITAL	**From 2004 Tax Return**	**Non-Distribution Elimination**	**Wires Only**
ADD:			
Reserves that have not been deducted in computing income for the year under Part I			0
Capital stock	5,585,838		5,585,838
Retained earnings	2,029,465		2,029,465
Contributed surplus	6,200,000		6,200,000
Any other surpluses			0
Deferred unrealized foreign exchange gains			0
All loans and advances to the corporation	5,585,838		5,585,838
All indebtedness- bonds, debentures, notes, mortgages, bankers acceptances, or similar obligations			0
Any dividends declared but not paid			0
All other indebtedness outstanding for more than 365 days			0
Subtotal	19,401,141	0	19,401,141
DEDUCT:			
Deferred tax debit balance			0
Any deficit deducted in computing shareholders' equity			0
Any patronage dividends 135(1) deducted in computing income under Part I included in amounts above			0
Deferred unrealized foreign exchange losses			0
			0
Subtotal	0	0	0
Capital for the year	19,401,141	0	19,401,141

Ontario Capital Tax, Large Corporation Tax

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

INVESTMENT ALLOWANCE	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Shares in another corporation			0
Loan or advance to another corporation	499,071		499,071
Bond, debenture, note, mortgage, or			0
similar obligation of another corporation			0
Long term debt of financial institution			0
Dividend receivable from another corporation			0
Debts of corporate partnerships that were not exempt from tax under Part I.3			0
Interest in a partnership			0
Investment Allowance	499,071	0	499,071

TAXABLE CAPITAL

Capital for the year	19,401,141	0	19,401,141
Deduct: Investment allowance	499,071	0	499,071
Taxable Capital for taxation year	18,902,070	0	18,902,070
Deduct: Capital Deduction upto $50,000,000	50,000,000		50,000,000
Taxable Capital	0	0	0
Rate			0.12500%
Gross Part I.3 Tax LCT			0.00
Federal Surtax Rate			1.1200%
Less: Federal Surtax = Taxable Income x Surtax Rate			2,292
Net Part I.3 Tax - LCT Payable ***(If surtax is greater than Gross LCT, then zero)***			0
Net Part I.3 Tax - LCT Payable grossed-up (1 - 0.1862)			0

Test Year PILs/ Tax Provision

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

	Wires Only	2004 Actual	Variance	Explanation of Variance
Regulatory Taxable Income - From 'Test Year Taxable Income'	204,614			
Corporate Income Tax Rate	18.62%			
Total Income Taxes	38,099			
Investment Tax Credits			0	
Miscellaneous Tax Credits			0	
Total Tax Credits	0	0	0	
Corporate PILs/Income Tax Provision for Test Year	38,099			
Ontario Capital Tax	26,412			
LCT	0			

INCLUSION IN RATES

Income Tax (grossed-up)	46,816
Ontario Capital Tax (not grossed-up)	26,412
LCT (grossed-up)	0
Tax Provision for 2006 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	73,228

PILs VARIANCE

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON Phone Number: 613-732-3687

		Income Taxes	OCT	LCT	TOTAL
Actual PILs/Taxes Paid by the Utility [1]	**2002**	76,897	39,000		115,897
	2003	221,972	41,300		263,272
	2004	168,599	42,600		211,199
Test Year PILs/Taxes [2]	**2006**	46,816	26,412	0	73,228
Variance (2006 vs. 2004)		- 121,783	- 16,188	-	- 137,971

Percentage Variance between Actual 2004 and 2006 Proxy -188%

If Cell K18 exceeds 25%, a narrative description of this variance <u>shall</u> be included in the Manager's Summary

Comments:

[1] Actual Wires-Only PILs/ Taxes paid includes income taxes, Ontario Capital Tax and Large Corporation Tax.
These values are available from your annual filings - SIMPIL model TaxRec

[2] Test Year PILs/Taxes include the grossed-up amounts for income taxes and Large Corporation Tax, plus Ontario Capital Tax.

2001 Fair Market Value (FMV) Bump

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	0	0	0
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	0	0	0
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	0	0	0
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	0	0	0
1855	Services	1	0	0	0
1860	Meters	1	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON **Phone Number:**

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	0	0	0
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	0	0	0
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	0	0	0
1855	Services	2	0	0	0
1860	Meters	2	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: OTTAWA RIVER POWER CORPORATION - Revision 2
License Number: ED-2003-0033
File Numbers: RP-2005-0020, EB-2005-0403
Name of Contact: JANE WILKINSON
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	0	0	0
1935	Stores Equipment	8	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	0	0	0
1960	Miscellaneous Equipment	8	0	0	0
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0
SUBTOTAL - CLASS 45			**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0
SUBTOTAL - CLASS 10			**0**	**0**	**0**
1925	Computer Software - CL12	12	0	0	0
SUBTOTAL - CLASS 12			**0**	**0**	**0**
1630	Leasehold Improvements	13_1	0	0	0
1710	Leasehold Improvements	13_2	0	0	0
1810	Leasehold Improvements	13_3	0	0	0
1910	Leasehold Improvements	13_4	0	0	0
SUBTOTAL - CLASS 13			**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	0	0	0
1610	Miscellaneous Intangible Plant	ECP	6,200,000	0	6,200,000
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**6,200,000**	**0**	**6,200,000**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
			0	0	0
	Total FMV Bump-up		**6,200,000**	**0**	**6,200,000**

Attachment 2 (of 3):

Latest Filed Federal Tax Return

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, 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 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*.

Identification

Business Number (BN) 001 87176 4072 RC0001

Corporation's name

002 Ottawa River Power Corporation

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 [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 283 Pembroke Street W

012

City: 015 Pembroke

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 K8A 5N5

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028)

021 c/o

022

023

City: 025

Province, territory, or state: 026

Country (other than Canada): 027

Postal code/Zip code: 028

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 [ ] 2 No [X]

(If **yes**, complete lines 031 to 038)

031 283 Pembroke Street W

032

City: 035 Pembroke

Province,territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 K8A 5N5

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 2008-01-01 (YYYY MM DD)

Tax year-end 061 2008-12-31 (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	092	093	094	095	096
100					

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.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	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	X	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		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		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		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	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	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
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

	Line	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	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

Additional information

	Line	1 Yes	2 No
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		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.

Line	Product	Line	%
284	Energy	285	100.000 %
286		287	%
288		289	%

	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible **294** ________ YYYY MM DD

If the corporation's major business activity is construction, did you have any sub-contractors during the tax year? **295** 1 Yes ☐ 2 No ☐

Taxable income

	Line		Amount	
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		310,373	A
Deduct: Charitable donations from Schedule 2	311			
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			►	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			310,373	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		310,373	
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)			310,373	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**	310,373	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**	310,373	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 2006 / Number of days in the tax year	/ 366	=	1
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	366 / 366	= 400,000	2
		Add amounts at lines 1 and 2		400,000	4

Business limit (see notes 1 and 2 below)	**410**	226,400	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	226,400	x **415** *** 23,060 D / 11,250	=	464,070 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 / Number of days in the tax year	/ 366	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	366 / 366	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	/ 366	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 2006 / Number of days in the tax year	/ 366	x	5 %	=	I
Amount H	x	Number of days in the tax year in 2007 / Number of days in the tax year	/ 366	x	7 %	=	J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J Enter amount K on line 10.	**438**		K

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			310,373	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		G		
Total of amounts B, C, D, E, F, and G		▶		H
Amount A **minus** amount H (if negative, enter "0")			310,373	I

Amount I	310,373	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=		J
Amount I	310,373	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=	26,382	K
Amount I	310,373	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=		L
Amount I	310,373	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=		L1

General tax reduction for Canadian-controlled private corporations – Total of amounts J, K, L, and L1 .... 26,382 M
Enter amount M on line 638.

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)				N
Amount Z1 from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Taxable resource income from line 435		Q		
Amount used to calculate the credit union deduction from Schedule 17		R		
Total of amounts O, P, Q, and R		▶		S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=		U
Amount T		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=		V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=		W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=		W1

General tax reduction – Total of amounts U, V, W, and W1 X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440**		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632					
Deduct:					
Foreign investment income from Schedule 7	**445**		x 9 1 / 3 % =		
			(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			310,373		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least					
Foreign non-business income tax credit from line 632		x 25 / 9 =			
Foreign business income tax credit from line 636		x 3 =			
		▶	310,373		
			x 26 2 / 3 % =	82,766	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			60,523		
Deduct: Corporate surtax from line 600					
Net amount			60,523	▶ 60,523	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			**450**		F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**			
Deduct: Dividend refund for the previous tax year	**465**			
			▶	G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	**480**			
			▶	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H			**485**	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	501,120	x 1 / 3	167,040	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **550** 117,942 A

Corporate surtax calculation

Base amount from line A above	117,942	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	31,037	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			31,037	7
Net amount (line 1 **minus** line 7)			86,905	8

Corporate surtax*

Line 8 86,905 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366 x 4 % = **600** 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			i
Taxable income from line 360	310,373		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	310,373 ▶	310,373	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** D

Subtotal (**add** lines A, B, C, and D) 117,942 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	**608**	31,037	
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 M	**638**	26,382	
General tax reduction from amount X	**639**		
Federal logging tax credit from Schedule 21	**640**		
Federal political contribution tax credit	**644**		
Federal political contributions **646**			
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		57,419 ▶	57,419 F

Part I tax payable – Line E **minus** line F . . . . . 60,523 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	60,523
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		60,523

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 Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	

Total tax payable 770 60,523 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	98,484
Total credits	890	98,484

Total credits ▶ 98,484 B

Refund code 894 1 Overpayment 37,961

Balance (line A **minus** line B) -37,961

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 ☒

Certification

I, 950 Fee (Last name in block letters) 951 Doug (First name in block letters) 954 President (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 2009-06-15 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (613) 732-3687 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 Jane Wilkinson (Name in block letters) 959 (613) 732-3687 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

- 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*.

Net income (loss) after taxes and extraordinary items per financial statements			323,027	A
Add:				
Provision for income taxes – current	101	79,893		
Amortization of tangible assets	104	788,567		
Tax reserves deducted in prior year from Schedule 13	125	70,000		
Reserves from financial statements – balance at the end of the year	126	70,000		
Subtotal of additions		1,008,460 ▶	1,008,460	
Other additions:				
Miscellaneous other additions:				
Subtotal of other additions	199	0 ▶	0	
Total additions	500	1,008,460 ▶	1,008,460	
Deduct:				
Capital cost allowance from Schedule 8	403	674,069		
Cumulative eligible capital deduction from Schedule 10	405	207,045		
Tax reserves claimed in current year from Schedule 13	413	70,000		
Reserves from financial statements – balance at the beginning of the year	414	70,000		
Subtotal of deductions		1,021,114 ▶	1,021,114	
Other deductions:				
Miscellaneous other deductions:				
Total	394			
Subtotal of other deductions	499	0 ▶	0	
Total deductions	510	1,021,114 ▶	1,021,114	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			310,373	

* For reference purposes only

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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
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

- 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.
- 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.

			Complete if payer corporation is connected		
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
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.

			If payer corporation is not connected, leave these columns blank.		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends	F2	G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 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	B	C	D
	Name of connected recipient corporation 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430
1	City of Pembroke			392,760
2	Village of Beachburg			13,230
3	Village of Killaloe			15,210
4	Town of Mississippi Mills			79,920
5				

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 501,120

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	501,120

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	501,120
Other dividends paid in the taxation year (total of 510 to 540)			
Total dividends paid in the taxation year		500	501,120
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			501,120

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

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 ☒ X

	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	Buildings	185,862	26,104		0	13,052	198,914	4	0	0	7,957	204,009
2	2	Poles, towers, fixtu	3,006,261	116,323		0	58,162	3,064,422	6	0	0	183,865	2,938,719
3	2	OH Conductors	2,177,057	193,634		0	96,817	2,273,874	6	0	0	136,432	2,234,259
4	2	UG conduit	1,499,729	57,024		0	28,512	1,528,241	6	0	0	91,694	1,465,059
5	2	UG conductors	1,311,442			0		1,311,442	6	0	0	78,687	1,232,755
6	8	Equipment	341,280			0		341,280	20	0	0	68,256	273,024
7	10	Computer Hardware & Vehicles	187,295	213,067		20,600	96,234	283,528	30	0	0	85,058	294,704
8	45	Computer Hardware	11,571			0		11,571	45	0	0	5,207	6,364
9	50	Computer hardware post March '		61,500		0	30,750	30,750	55	0	0	16,913	44,587
		Total	8,720,497	667,652		20,600	323,527	9,044,022				674,069	8,693,480

* 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.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	Ottawa River Energy Solutions Inc.		86613 9025 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

Canada

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
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

- 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	2,957,785	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	2,957,785	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)				2,957,785	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		249			
amount K	2,957,785				
less amount from line 249					
Current year deduction	2,957,785 x 7.00 % =	250	207,045 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			207,045 ►	207,045	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	2,750,740	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	

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business Number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- References to parts, sections, subsections, paragraphs, and subparagraphs are from the federal *Income Tax Act*.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on amalgamation or wind-up of subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The total capital gains reserve at the beginning of the taxation year plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary should be entered on line 880, and the total capital gains reserve at the end of the taxation year, should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

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 $
Reserve for doubtful debts	X	110 70,000	115			120 70,000
Reserve for undelivered goods and services not rendered		130	135			140
Reserve for prepaid rent		150	155			160
Reserve for December 31, 1995 income		170	175			180
Reserve for refundable containers		190	195			200
Reserve for unpaid amounts		210	215			220
Insurance corporation policy reserves						
Bank reserves						
Other tax reserves		230	235			240
Totals		270 70,000	275			280 70,000

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 plus the amount from line 275 should be entered on line 125 of Schedule 1 as an addition.
The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

T2 SCH 13 E (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	96,659	1245045-01			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	96,659	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	96,659	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (06)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 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 agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
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.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400	
1	Ottawa River Power Corporation	87176 4072 RC0001	1	400,000	56.6000	226,400	
2	Ottawa River Energy Solutions Inc.	86613 9025 RC0001	1	400,000	43.4000	173,600	
				Total	100.0000	400,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC 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.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

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	Corporation of the City of Pembroke	12193 6140 RC0001			79.000	
2	Corporation of The Town of Mississippi Mills	86626 6653 RC0001			16.000	
3						
4						
5						
6						
7						
8						
9						
10						

T2 SCH 50 (06)

Canada

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2008-12-31

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		501,120			
Total taxable dividends paid in the tax year	100	501,120			
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	1,522,442	
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.

Attachment 3 (of 3):

Latest Filed Ontario Tax Return

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)*
Ottawa River Power Corporation

Mailing Address
283 Pembroke Street W
Pembroke
ON CA K8A 5N5

Has the mailing address changed since last filed CT23 Return? [ ] Yes
Date of Change (year month day)

Registered/Head Office Address
283 Pembroke Street W
Pembroke
ON CA K8A 5N5

Location of Books and Records
283 Pembroke Street W
Pembroke
ON CA K8A 5N5

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Jane Wilkinson	(613) 732-3687	

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)
1353485

This Return covers the Taxation Year
Start (year month day): 2008-01-01
End (year month day): 2008-12-31

Date of Incorporation or Amalgamation (year month day): 1999-04-29

Ontario Corporation No. (MGS): 1353485

Canada Revenue Agency Business No.
If applicable, enter
87176 4072 RC0001

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*

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**

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Ministry Use

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)*
Doug Fee

Title D [ ] Director O [ ] Officer P [X] 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) ______ %

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

Distribution of ele

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	310,373
Subtract: Charitable donations	–	1	
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 704	
Net capital losses (page 16) From 715 ______ 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	310,373

		Line	Amount
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	310,373

Taxable Income

Number of Days in Taxation Year

From	Amount		Ontario Allocation		Rate		Days	÷	Total Days		Line	Amount
10 (or 20 if applicable)	310,373	x 30	100.0000 %	x	12.5 %	x	33 (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷	73: 366	= +	29	
10 (or 20 if applicable)	310,373	x 30	100.0000 %	x	14 %	x	34 (Days after Dec. 31, 2003): 366	÷	73: 366	= +	32	43,452

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40: 43,452

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

		Line	Amount		Line	Amount
* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))					50	310,373
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51	310,373			
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				
	=		310,373	►	54	310,373
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	226,400			

Ontario Business Limit Calculation

		Days	÷	**		Line	Amount
320,000	x	31 (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷	366	= +	46	
400,000	x	34 (Days after Dec. 31, 2003): 366	÷	366	= +	47	

Business Limit for Ontario purposes 46 + 47 = 44: 500,000 x 48 (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.): 56.6000 % = 45: 283,000

Income eligible for the IDSBC From 30: 100.0000 % (***Ontario Allocation) x 56: 283,000 (Least of 50, 54 or 45) = 60: 283,000

* ***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*

Number of Days in Taxation Year

Calculation of IDSBC Rate 7 % x Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 366 = + [89] .

8.5 % x Days after Dec. 31, 2003 [34] 366 ÷ Total Days [73] 366 = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] = [78] 8.5000

Claim From [60] 283,000 x From [78] 8.5000 % = [70] 24,055

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 500,000 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] 310,373

If you are a member of an associated group (X) [81] **X** (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)
Ottawa River Energy Solutions Inc.	1800159	2008-12-31	+ [82]	171,673
			+ [83]	
			+ [84]	

Aggregate Taxable Income [80] + [82] + [83] + [84], etc. = [85] 482,046

Number of Days in Taxation Year

320,000 x Days after Dec. 31, 2002 and before Jan. 1, 2004 [31] ÷ Total Days [73] 366 = + [115]

400,000 x Days after Dec. 31, 2003 [34] 366 ÷ Total Days [73] 366 = + [116]

[115] + [116] = 500,000 – [114] 500,000

(If negative, enter nil) = [86]

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax 4.6670 % x Days after Dec. 31, 2002 [38] ÷ Total Days [73] 366 = + [97] 4.2500

From [86] x From [97] 4.2500 % = [87]

From [87] x From [60] 283,000 ÷ From [114] 500,000 = [88]

Surtax Lesser of [70] or [88] = [100]

**** 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)*

Additional Deduction for Credit Unions	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	283,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 ______ ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 ______

*Ontario Allocation

Lesser of 56 or 121	+		122	
120 – 56 + 122	=		130	
Taxable Income	+	From	10	310,373
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	–	From	56	283,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	+	From	122	
Subtract: Taxable Income 10 310,373 X Allocation % to jurisdictions outside Canada	–		140	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	–		141	
10 – 56 + 122 – 140 – 141	=		142	27,373

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: 73 366	= +	154
143 ______ (Lesser of 130 or 142)	x From 30	100.0000 % (Ontario Allocation)	x 2 %	x Days after Dec. 31, 2003: 34 366	÷ Total Days: 73 366	= +	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 19,397

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

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)

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. No. of Graduates From 6596 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)

Applies to employment of eligible apprentices. No. of Apprentices From 5896 202

Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 19,397

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	21,209,789
Total Revenue of the corporation	+ 241	18,751,622

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 **X** (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
Ottawa River Energy Solutions Inc.	1800159	2008-12-31	+ 243	1,585,528	+ 244	628,392
			+ 245		+ 246	
			+ 247		+ 248	

Aggregate Total Assets	240 + 243 + 245 + 247 , etc.	= 249	22,795,317
Aggregate Total Revenue	241 + 244 + 246 + 248 , etc.	= 250	19,380,014

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 402,920 (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276 16,117

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	–	277	
Subtract: Income Tax	–	From 190	19,397
Net CMT Payable (If negative, enter Nil on Page 17.)	=	280	-3,280

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	19,397
Gross CMT Payable	+ From 276	16,117			
Subtract: Foreign Tax Credit for CMT purposes	– From 277				
If 276 – 277 is negative, enter NIL in 290	=	16,117	–	290	16,117
Income Tax eligible for CMT Credit			=	300	3,280

B.

Income Tax (after deduction of specified credits)	+	From 230	19,397
Subtract: CMT credit used to reduce income taxes	–	310	
Income Tax	=	320	19,397

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	5,585,838
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	2,120,422
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	6,200,000
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	5,585,838
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	787,045
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	20,279,143
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
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	20,279,143
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	20,279,143

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	692,310
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	692,310

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	21,209,789
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	21,209,789
Amounts in 360 and 361 (if deducted from assets)	+	440	787,045
Subtract: Amounts in 371 , 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	21,996,834

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	638,249
Taxable Capital 390 – 460	=	470	19,640,894

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	18,751,622
Total Assets (as adjusted)	From 430	21,209,789

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

Amount		Days			Total Days			Result
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)		÷ 73	366	= +	501	
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007)		÷ 73	366	= +	502	
12,500,000	x	38 (Days after Dec. 31, 2006 and before Jan. 1, 2008)		÷ 73	366	= +	504	
15,000,000	x	39 (Days after Dec. 31, 2007)	366	÷ 73	366	= +	505	15,000,000

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 15,000,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

Rate		Days			Total Days			Result
0.3 %	x	556 (Days before Jan. 1, 2007)		÷ 73	366	= +	511	%
0.225 %	x	557 (Days after Dec. 31, 2006 and before Jan. 1, 2009)	366	÷ 73	366	= +	512	0.2250 %

Capital Tax Rate 511 + 512 = 516 0.2250 %

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 ______

– From 503 ______

= 471 ______ x From 30 100.0000 % Ontario Allocation x From 516 0.2250 % Capital Tax Rate x Days in taxation year 555 366 / 366 (366 if leap year) = + 523 ______

If floating taxation year, refer to Guide.

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. [X] 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 19,640,894

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
Ottawa River Energy Solutions Inc.	1800159	2008-12-31	+ 531	1,244,372
			+ 532	
			+ 533	

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - - = 540 20,885,266

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 19,640,894 ÷ From 540 20,885,266 x From 503 15,000,000 = 541 14,106,280

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	19,640,894
–	542	14,106,280
=	471	5,534,614

471 5,534,614 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) x 555 366 (Days in taxation year) / * 366 (366 if leap year) = + 523 12,453 (**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 0.2250 % (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 555 366 (Days in taxation year) / * 366 (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 12,453

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - – 546

Capital Tax 543 – 546 *(amount cannot be negative)* - - - - = 550 12,453

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 555 366 (Days in taxation year) / 366* (366 if leap year) = + 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

570 ______ x 571 ______% x From 30 100.0000 % x 555 366 (Days in taxation year) / 366* (366 if leap year) = + 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

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 ± 600 310,373
Transfer to Page 15

Add:

Item	Line	Amount
Federal capital cost allowance	+ 601	674,069
Federal cumulative eligible capital deduction	+ 602	207,045
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	70,000
Federal allowable reserves. Balance end of year	+ 605	70,000
Ontario non-allowable reserves. Balance end of year	+ 606	70,000
Ontario allowable reserves. Balance beginning of year	+ 607	70,000
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 (Total Days) 366 = + 633 ______

612 ______ x 5 / 14 x 34 (Days after Dec. 31, 2003) 366 ÷ 73 (Total Days) 366 = + 634 ______

Item	Line	Amount
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	
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 = 1,161,114 ▶ 640 1,161,114
Transfer to Page 15

Deduct:

Item	Line	Amount
Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	674,069
Ontario cumulative eligible capital deduction	+ 651	207,045
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	70,000
Ontario allowable reserves. Balance end of year	+ 654	70,000
Federal non-allowable reserves. Balance end of year	+ 655	70,000
Federal allowable reserves. Balance beginning of year	+ 656	70,000
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 1,161,114
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	310,373
Total of Additions on page 14	From =	640	1,161,114
Sub Total of deductions on page 14	From =	681	1,161,114

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	
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 = 1,161,114 ▶ 680 1,161,114

Net income (loss) for Ontario Purposes 600 + 640 – 680 = 690 310,373

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 1999-12-31	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2000-12-31	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2001-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2002-12-31	820	830	840	853	873
804	5th preceding taxation year 2003-12-31	821	831	841	854	874
805	4th preceding taxation year 2004-12-31	822	832	842	855	875
806	3rd preceding taxation year 2005-12-31	823	833	843	856	876
807	2nd preceding taxation year 2006-12-31	824	834	844	857	877
808	1st preceding taxation year 2007-12-31	825	835	845	858	878
809	Current taxation year 2008-12-31	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	2005-12-31	911	921	931	941
ii) 2nd preceding	902	2006-12-31	912	922	932	942
iii) 1st preceding	903	2007-12-31	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		19,397
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		12,453
Premium Tax	+ From 590		
Total Tax Payable	=	950	31,850
Subtract: Payments	–	960	
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	31,850
If payment due	Enclosed *	990	31,850
If overpayment: Refund *(Refer to Guide)*	=	975	
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)*
Doug Fee

Title
President

Full Residence Address

Signature

Date
2009-06-15

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Ottawa River Power Corporation	1353485	2008-12-31

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)

Item		Code	Amount		Code	Amount
Net Income/Loss (unconsolidated, determined in accordance with GAAP)				±	2100	323,027
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	79,893			
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	=		79,893	+	2116	79,893

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

Item		Code	Amount		Code	Amount
** 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	

Item		Code	Amount
Subtotal (Additions) =	+	2129	
Subtotal (Subtractions) =	–	2130	
** Other adjustments	±	2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131	=	2132	402,920
** 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	402,920

Deduct:		Code	Amount		Code	Amount
* 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.*

		Code	Amount
CMT Base	=	2136	402,920

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
Ottawa River Power Corporation	1353485	2008-12-31

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 1999-12-31	2260	2280
2241	8th preceding taxation year 2000-12-31	2261	2281
2242	7th preceding taxation year 2001-12-31	2262	2282
2243	6th preceding taxation year 2002-12-31	2263	2283
2244	5th preceding taxation year 2003-12-31	2264	2284
2245	4th preceding taxation year 2004-12-31	2265	2285
2246	3rd preceding taxation year 2005-12-31	2266	2286
2247	2nd preceding taxation year 2006-12-31	2267	2287
2248	1st preceding taxation year 2007-12-31	2268	2288
2249	Current taxation year 2008-12-31	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
Ottawa River Power Corporation	1353485	2008-12-31

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 1999-12-31	2360	2380
2341	8th preceding taxation year 2000-12-31	2361	2381
2342	7th preceding taxation year 2001-12-31	2362	2382
2343	6th preceding taxation year 2002-12-31	2363	2383
2344	5th preceding taxation year 2003-12-31	2364	2384
2345	4th preceding taxation year 2004-12-31	2365	2385
2346	3rd preceding taxation year 2005-12-31	2366	2386
2347	2nd preceding taxation year 2006-12-31	2367	2387
2348	1st preceding taxation year 2007-12-31	2368	2388
2349	Current taxation year 2008-12-31	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
Ottawa River Power Corporation	1353485	2008-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss 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	1999-04-28					
9th Prior Year	1999-12-31					
8th Prior Year	2000-12-31					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	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
1999-04-28						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Ottawa River Power Corporation	1353485	2008-12-31

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
1999-04-28						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Ottawa River Power Corporation	1353485	2008-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-04-28					
9th Prior Year	1999-12-31					
8th Prior Year	2000-12-31					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	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
1999-04-28						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
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
1999-04-28						
1999-12-31						
2000-12-31						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

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
Ottawa River Power Corporation	1353485	2008-12-31

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)

Notes payable	+	5,585,838
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	5,585,838

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
Ottawa River Power Corporation	1353485	2008-12-31

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	185,862	26,104		0	211,966	13,052	198,914	4	0	0	7,957	204,009
2	3,006,261	116,323		0	3,122,584	58,162	3,064,422	6	0	0	183,865	2,938,719
2	2,177,057	193,634		0	2,370,691	96,817	2,273,874	6	0	0	136,432	2,234,259
2	1,499,729	57,024		0	1,556,753	28,512	1,528,241	6	0	0	91,694	1,465,059
2	1,311,442			0	1,311,442		1,311,442	6	0	0	78,687	1,232,755
8	341,280			0	341,280		341,280	20	0	0	68,256	273,024
10	187,295	213,067		20,600	379,762	96,234	283,528	30	0	0	85,058	294,704
45	11,571			0	11,571		11,571	45	0	0	5,207	6,364
50		61,500		0	61,500	30,750	30,750	55	0	0	16,913	44,587
Totals	8,720,497	667,652		20,600	9,367,549	323,527	9,044,022				674,069	8,693,480

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 Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Ottawa River Power Corporation	1353485	2008-12-31

- **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)*			= + 2,957,785	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			= 2,957,785	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			= 2,957,785	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**	2,957,785			
From **N**	–			
Current year deduction M minus N	= 2,957,785	x 7 % = + 207,045	O	
N + O		= 207,045	– 207,045	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)*	= 2,750,740	Q

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Ottawa River Power Corporation	1353485	2008-12-31

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** ______ x 1 / 2				=	– U
T minus U *(if negative, enter zero)*					= V
From **V** ______ x 2 / 3					= W
Lesser of **R** and **S**				=	+ Z
Amount to be included in income W + Z					=

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Ottawa River Power Corporation	1353485	2008-12-31

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	70,000				70,000
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 70,000	E			F 70,000

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
Reserves from Part 2	70,000					70,000
Totals	70,000					70,000
	Enter in box 653 *of the CT23*					*Enter in box* 606 *of the CT23*

ALLOWANCE FOR PILS

Attachment 1 shows the PILs model used to calculate the PILs amount for 2009, 2010 at existing rates and 2010 at proposed rates.

The proposed Allowance for PILs for the 2010 test year is based on the proposed Return on Equity (ROE) amount – see Exhibit 5, Tab 1, Schedule 1, Attachment 1. The resulting income taxes payable amount is grossed-up based on the applicable income tax rate, so the revenue requirement will generate the proposed ROE amount on an after-tax basis.

Taxable income is based on pre-tax (accounting) income, plus depreciation expense, less deductions for Capital Cost Allowance and Cumulative Eligible Capital.

The utility's Taxable Capital is less than the exempt amount for the Ontario Capital Tax; accordingly no capital tax is payable.

Attachment 1 (of 1):

Proposed PILs Model

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

Model Overview

Select a worksheet link

Tab	ShortName	Title	Instruction	Link
P		**PILS Calculationa**		P0 Administration
P0	Admin	Administration	Enter administrative information about the Application	P0 Administration
P1	UCC	Undepreciated Capital Costs (UCC)	Enter actual balances and projected asset additions & retirements	P1 Undepreciated Capital Costs (UCC)
P2	CEC	Cumulative Eligible Capital (CEC)	Enter actual balance, projected changes and deduction rates	P2 Cumulative Eligible Capital (CEC)
P3	Interest	Interest Expense	Enter deemed and projected actual interest amounts	P3 Interest Expense
P4	LCF	Loss Carry-Forward (LCF)	Enter details of historical losses available to offset projected taxable income	P4 Loss Carry-Forward (LCF)
P5	Reserves	Reserve Balances	Enter balance amounts and projected changes in tax and accounting reserves	P5 Reserve Balances
P6	TxblIncome	Taxable Income	Enter amounts required to calculate taxable income	P6 Taxable Income
P7	CapitalTax	Capital Taxes	Enter rate base amounts	P7 Capital Taxes
P8	TotalPILs	Total PILs Expense	Enter tax credit amounts	P8 Total PILs Expense
Y		**Reference Information**		Y1 Tax Rates and Exemptions
Y1	TaxRates	Tax Rates and Exemptions	Enter applicable rates and exemption amounts	Y1 Tax Rates and Exemptions
Y2	CCA	Capital Cost Allowances (CCA)	Enter asset classes and applicable rates for CCA deductions	Y2 Capital Cost Allowances (CCA)
Z		**Model Parameters**		Z1 Model Variables
Z1	ModelVariables	Model Variables		Z1 Model Variables
Z0	Disclaimer	Software Terms of Use		Z0 Software Terms of Use

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P0 Administration

Enter administrative information about the Application

Application Version	
Name of Applicant	Ottawa River Power Corporation
License Number	ED-2003-0033
Test Year	2010
File Number(s)	EB-2009-0165
Date of Application	30-Jun-2010
Contact:	
Name	Jane Wilkinson
email	jwilkinson@orpowercorp.com
phone	613.732.3687
Date of previous Test Year approval	12-Apr-2006

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions & retirements

Class	Description	UCC Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment
1	Distribution System - post 1987	204,009		
2	Distribution System - pre 1988	6,160,504		
8	General Office/Stores Equip	273,024		
10	Computer Hardware/ Vehicles	294,704		
10.1	Certain Automobiles			
12	Computer Software			
13.1	Leasehold Improvement # 1			
13.2	Leasehold Improvement # 2			
13.3	Leasehold Improvement # 3			
13.4	Leasehold Improvement # 4			
14	Franchise			
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			
43.1	Certain Energy-Efficient Electrical Generating Equipment			
45	Computers & Systems Software acq'd post Mar 22/04	6,364		
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			
47	Distribution System post Feb 22/05	1,710,288		
50	Computer Equipment Post March 18, 2007	44,587		
52	Computer Equipment January 28/09 - January 31/2010			
	TOTAL	**8,693,480**		

[1] per Schedule 8 of 2008 corporate tax return

Ottawa River Power Corporation (ED-2003-(

PILs Calculations for 2010 EDR Application (EB-2009-016!

June 30, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA
1	Distribution System - post 1987	6,329		210,338	3,165	207,174	4.0%	8,287
2	Distribution System - pre 1988			6,160,504		6,160,504	6.0%	369,630
8	General Office/Stores Equip			273,024		273,024	20.0%	54,605
10	Computer Hardware/ Vehicles	14,240		308,944	7,120	301,824	30.0%	90,547
10.1	Certain Automobiles						30.0%	
12	Computer Software	4,202		4,202	2,101	2,101	100.0%	2,101
13.1	Leasehold Improvement # 1						25 years	
13.2	Leasehold Improvement # 2						4 years	
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise						6 years	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			6,364		6,364	45.0%	2,864
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	942,094		2,652,382	471,047	2,181,335	8.0%	174,507
50	Computer Equipment Post March 18, 2007			44,587		44,587	55.0%	24,523
52	Computer Equipment January 28/09 - January 31/2010	11,156		11,156		11,156	100.0%	11,156
	TOTAL	**978,021**		**9,671,501**	**483,433**	**9,188,069**		**738,220**

¹ per Schedule 8 of 2008 corporate tax return

Ottawa River Power Corporation (ED-2003-(

PILs Calculations for 2010 EDR Application (EB-2009-016

June 30, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC ☐ 31 Dec/09
1	Distribution System - post 1987	202,051
2	Distribution System - pre 1988	5,790,874
8	General Office/Stores Equip	218,419
10	Computer Hardware/ Vehicles	218,397
10.1	Certain Automobiles	
12	Computer Software	2,101
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	3,500
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	2,477,875
50	Computer Equipment Post March 18, 2007	20,064
52	Computer Equipment January 28/09 - January 31/2010	
	TOTAL	**8,933,281**

[1] per Schedule 8 of 2008 corporate tax return

Ottawa River Power Corporation (ED-2003-(

PILs Calculations for 2010 EDR Application (EB-2009-0165

June 30, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2010 Projected Additions	2010 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2010 CCA
1	Distribution System - post 1987			202,051		202,051	4.0%	8,082
2	Distribution System - pre 1988			5,790,874		5,790,874	6.0%	347,452
8	General Office/Stores Equip	8,000		226,419	4,000	222,419	20.0%	44,484
10	Computer Hardware/ Vehicles	302,000		520,397	151,000	369,397	30.0%	110,819
10.1	Certain Automobiles						30.0%	
12	Computer Software	18,700		20,801	9,350	11,451	100.0%	11,451
13.1	Leasehold Improvement # 1							
13.2	Leasehold Improvement # 2							
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise							
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			3,500		3,500	45.0%	1,575
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	832,630		3,310,505	416,315	2,894,190	8.0%	231,535
50	Computer Equipment Post March 18, 2007	6,000		26,064	3,000	23,064	55.0%	12,685
52	Computer Equipment January 28/09 - January 31/2010						100.0%	
	TOTAL	**1,167,330**		**10,100,611**	**583,665**	**9,516,946**		**768,084**

¹ per Schedule 8 of 2008 corporate tax return

Ottawa River Power Corporation (ED-2003-(

PILs Calculations for 2010 EDR Application (EB-2009-016!

June 30, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC ☐ 31 Dec/10
1	Distribution System - post 1987	193,969
2	Distribution System - pre 1988	5,443,421
8	General Office/Stores Equip	181,935
10	Computer Hardware/ Vehicles	409,578
10.1	Certain Automobiles	
12	Computer Software	9,350
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	1,925
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	3,078,970
50	Computer Equipment Post March 18, 2007	13,379
52	Computer Equipment January 28/09 - January 31/2010	
	TOTAL	**9,332,527**

¹ per Schedule 8 of 2008 corporate tax return

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P2 Cumulative Eligible Capital (CEC)

Enter actual balance, projected changes and deduction rates

	2009			2010		
CEC Opening Balance [1]			**2,750,740**			**2,558,188**
Eligible Capital Property (ECP) Acquisitions						
Other Adjustments						
Subtotal		**x 3/4 =**			**x 3/4 =**	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		**x 1/2 =**			**x 1/2 =**	
Amount transferred on amalgamation or wind-up of subsidiary						
Subtotal before deductions			**2,750,740**			**2,558,188**
ECP Dispositions (net)						
Other Adjustments						
Subtotal		**x 3/4 =**			**x 3/4 =**	
Balance before tax deduction			**2,750,740**			**2,558,188**
Tax Deduction	*Rate:*	***7.0%***	**192,552**	*Rate:*	***7.0%***	**179,073**
CEC Ending Balance			**2,558,188**			**2,379,115**

[1] 2009 amount per ending balance on Schedule 10 of 2008 corporate rax return

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P3 Interest Expense

Enter deemed and projected actual interest amounts

	2009	2010	
Deemed Interest Expense (A)	404,973	404,973	
3900-Interest Expense			
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)			
			Enter other adjustments for tax purposes
Total Interest Projected (B)			
Excess Interest Expense			*(B) less (A); if negative: zero*

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P4 Loss Carry-Forward (LCF)

Enter details of historical losses available to offset projected taxable income

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	2009	2010
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] *per Schedule 7-1 of 2008 corporate tax return*

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P5 Reserve Balances

Enter balance amounts and projected changes in tax and accounting reserves

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09	Changes (+ / -) in 2010	Balance 31 Dec/10
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)	70,000		70,000	5,000	75,000		75,000
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL	**70,000**		**70,000**	**5,000**	**75,000**		**75,000**
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts	70,000		70,000	5,000	75,000		75,000
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL	**70,000**		**70,000**	**5,000**	**75,000**		**75,000**

[1] per Schedule 13 of 2008 corporate tax return

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		775,183		775,183	416,635	149,898	453,821
Additions:							
Interest and penalties on taxes	103	2,168		2,168			
Amortization of tangible assets	104	672,636		672,636	788,522	791,805	791,805
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112						
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121						
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125	112,085		112,085	70,000	75,000	75,000
Reserves from financial statements- balance at end of year	126	131,846		131,846	75,000	75,000	75,000

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		775,183		775,183	416,635	149,898	453,821
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Total Additions		**918,735**		**918,735**	**933,522**	**941,805**	**941,805**

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		775,183		775,183	416,635	149,898	453,821
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	698,099		698,099	738,220	768,084	768,084
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405	276,779		276,779	192,552	179,073	179,073
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413	131,846		131,846	75,000	75,000	75,000
Reserves from financial statements - balance at beginning of year	414	112,085		112,085	70,000	75,000	75,000
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Total Deductions		**1,218,809**		**1,218,809**	**1,075,771**	**1,097,157**	**1,097,157**

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		775,183		775,183	416,635	149,898	453,821
NET INCOME (LOSS) FOR TAX PURPOSES		**475,109**		**475,109**	**274,386**	**(5,454)**	**298,469**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**475,109**		**475,109**	**274,386**	**(5,454)**	**298,469**

[1] 2009 Projection = "Earnings before Tax' (sheet E1); 2010 @ existing rates = "Earnings before Tax' (sheet E2); 2010 @ new dist. rates = "Deemed Return On Equity' (sheet E3)

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P7 Capital Taxes

Enter rate base amounts

Rates and exemptions from sheet Y1

	2009	2010	
OCT (Ontario Capital Tax):			
Rate Base	11,253,618	11,288,948	*'Calculated Value' from sheet E3*
Less: Exemption	15,000,000	15,000,000	
Deemed Taxable Capital			
Tax Rate	0.225%	0.075%	
OCT payable			
Federal LCT (Large Corporations Tax):			
Rate Base	11,253,618	11,288,948	
Less: Exemption	50,000,000	50,000,000	
Deemed Taxable Capital			
Tax Rate			
LCT payable			

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

P8 Total PILs Expense

Enter tax credit amounts

	2009 Projection	2010 Projection [1]	2010 Test [1]	
Regulatory Taxable Income/(Loss)	274,386	(5,454)	298,469	*from sheet P6*
Combined Income Tax Rate	16.50%		16.00%	*"t" (from sheet Y1)*
Total Income Taxes	45,274		47,755	
Investment & Miscellaneous Tax Credits				*Input amounts*
Income Tax Payable	**45,274**		**47,755**	*"i"*
Large Corporations Tax (LCT)				*from sheet P7*
Ontario Capital Tax (OCT)				*from sheet P7*
Grossed-up Income Tax			56,851	*= i / (1 - t)*
Grossed-up LCT				*= LCT / (1 - t)*
Total PILs Expense	**45,274**		**56,851**	***Enter these results on sheet E4***

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

Y1 Tax Rates and Exemptions

Enter applicable rates and exemption amounts

2009 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.50%	16.50%	
$400,000	$500,000	19.00%	5.50%	24.50%	
$500,000	$1,500,000	19.00%	14.00%	33.00%	4.25%
$1,500,000		19.00%	14.00%	33.00%	

2009 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$15,000,000
Capital Tax Rate		0.225%
Surtax Rate		

2010 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.00%	16.00%	
$400,000	$500,000	18.00%	5.00%	23.00%	
$500,000	$1,500,000	18.00%	13.00%	31.00%	2.13%
$1,500,000		18.00%	13.00%	31.00%	

2010 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$15,000,000
Capital Tax Rate		0.075%
Surtax Rate		

Ottawa River Power Corporation (ED-2003-0033)

PILs Calculations for 2010 EDR Application (EB-2009-0165)

June 30, 2010

Y2 Capital Cost Allowances (CCA)

Enter asset classes and applicable rates for CCA deductions

Class	Description	Rate	Years	½ Year Rule
1	Distribution System - post 1987	4.0%		YES
2	Distribution System - pre 1988	6.0%		YES
8	General Office/Stores Equip	20.0%		YES
10	Computer Hardware/ Vehicles	30.0%		YES
10.1	Certain Automobiles	30.0%		YES
12	Computer Software	100.0%		YES
13.1	Leasehold Improvement # 1		25	YES
13.2	Leasehold Improvement # 2		4	YES
13.3	Leasehold Improvement # 3			YES
13.4	Leasehold Improvement # 4			YES
14	Franchise		6	NO
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	8.0%		YES
43.1	Certain Energy-Efficient Electrical Generating Equipment	30.0%		YES
45	Computers & Systems Software acq'd post Mar 22/04	45.0%		YES
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	30.0%		YES
47	Distribution System post Feb 22/05	8.0%		YES
50	Computer Equipment Post March 18, 2007	55.0%		YES
52	Computer Equipment January 28/09 - January 31/2010	100.0%		NO

Exhibit 5:

COST OF CAPITAL AND RATE OF RETURN

Exhibit 5: Cost Of Capital And Rate Of Return

Tab 1 (of 1): Cost of Capital and Rate of Return

CAPITAL STRUCTURE

Attachment 1 shows the capital structure, cost rates and related amounts from the 2006 Board-approved figures, 2007-09 actuals as approved in distribution rates for those years, and the proposed figures for the 2010.

The total capitalized amount for 2006-09 corresponds to the 2006 Board-approved rate base. The total capitalized amount for 2010 corresponds to the proposed rate base in this application. The derivation of the rate base amounts appears in Exhibit 2, Tab 1, Schedule 1, Attachment 1.

ORPC's Board-approved capital structure in 2006 was 50% debt, 50% equity. These weightings transitioned to 60% debt, 40 % equity over three years beginning in 2008, in accordance with the Board's direction.[1] The proposed capital structure for 2010 also reflects a short-term debt component of 4% directed by the Board.[2]

The cost rates for 2006-09 correspond to those approved by the Board in 2006. The cost rates proposed for 2010 are described in Exhibit 5, Tab1, Schedule 2.

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[1] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006.

[2] *ibid.*

Capitalization and Cost of Capital

2006 EDR Approved

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	50.00%	5,379,768	7.25%	390,033
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	50.00%	5,379,768	7.25%	390,033
	Equity				
4	Common Equity	50.00%	5,379,768	9.00%	484,179
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	50.00%	5,379,768	9.00%	484,179
	Total	100.00%	10,759,535	8.13%	874,212

Capitalization and Cost of Capital

Line No.	Particulars	Capitalization Ratio 2007 (%)	($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	50.00%	5,379,768	7.25%	390,033
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	50.00%	5,379,768	7.25%	390,033
	Equity				
4	Common Equity	50.00%	5,379,768	9.00%	484,179
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	50.00%	5,379,768	9.00%	484,179
	Total	100.00%	10,759,535	8.13%	874,212

Capitalization and Cost of Capital

Line No.	Particulars	2008 Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	53.33%	5,738,419	7.25%	416,035
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	53.33%	5,738,419	7.25%	416,035
	Equity				
4	Common Equity	46.67%	5,021,116	9.00%	451,900
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	46.67%	5,021,116	9.00%	451,900
	Total	100.00%	10,759,535	8.07%	867,936

Capitalization and Cost of Capital

Line No.	Particulars	2009 Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.67%	6,097,070	7.25%	442,038
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	56.67%	6,097,070	7.25%	442,038
	Equity				
4	Common Equity	43.33%	4,662,465	9.00%	419,622
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	43.33%	4,662,465	9.00%	419,622
	Total	100.00%	10,759,535	8.01%	861,659

Capitalization and Cost of Capital

Line No.	Particulars	2010 Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	6,450,245	7.25%	467,643
2	Short-term Debt	4.00%	460,732	2.07%	9,537
3	Total Debt	60.00%	6,910,976	6.90%	477,180
	Equity				
4	Common Equity	40.00%	4,607,318	9.85%	453,821
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	40.00%	4,607,318	9.85%	453,821
	Total	100.00%	11,518,294	8.08%	931,001

COST OF CAPITAL

The proposed cost rates for cost of capital in 2010 are presented on the last page of Exhibit 5, Tab 1, Schedule 2, Attachment 1. The rates shown for short-term debt and return on equity are those set out in the Board's letter of February 24, 2010, *Cost of Capital Parameter Updates for 2010 Cost of Service Applications*.

The calculation of the proposed rate for long-term debt is set out in Attachment 1 to this schedule, based on the weighted average cost of debt in 2010. There are four debt instruments outstanding in the year, comprised of Promissory Notes (the "Notes") payable to each of the utility's shareholders under identical terms.

The terms of the Notes are embedded in an agreement between ORPC and each of its shareholders (the "Agreement"), which appears in Attachment 2 to this schedule. Since market opening in May 2002, ORPC has paid interest on the Notes at a fixed rate of 7.25%. The Notes have a fixed term of 20 years, as set out in section 13.0(h) of the Agreement. The Notes are not callable: the only condition under which the Notes become payable prior to the end of the 20-year term is a sale of ORPC, as stated in section 13.0(j) of the Agreement. No such sale is contemplated.

The interest rate on the Notes is not variable: the only conditions under which the interest rate may change are set out in section 13.0 of the Agreement, paragraphs (e) and (f). The Board's current policy on Cost of Capital[1] is the only applicable 'regulation' under these paragraphs, and no other interest rate for long-term debt is prescribed under that policy. The actual 7.25% interest rate is identical to the Board's deemed debt rate at the time the Notes were issued. As such, the actual interest rate has been used for rate-setting purposes, in accordance with the Board's policy: *Affiliate*

[1] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009

embedded/actual debt with fixed rates, terms and maturity will get the lower of actual and deemed debt rate at time of issuance.[2]

[2] *Ibid.*, page 59

Weighted Average Cost of Debt

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate	Other Costs	Use Deemed Rate?	Annual Cost
Promissory Note	4,364,000	1-Jan-2000	1-May-2022	7.25%		NO	316,390
Promissory Note	147,000	1-Jan-2000	1-May-2022	7.25%		NO	10,658
Promissory Note	172,348	1-Oct-2000	1-May-2022	7.25%		NO	12,495
Promissory Note	902,490	1-Oct-2000	1-May-2022	7.25%		NO	65,431

Description	Effective Rate	Days o/s in 2010	Average Balance	2010 Cost	2010 Ending Balance	Debt o/s USA #	Int. Expense USA #
Promissory Note	7.25%	365	4,364,000	316,390	4,364,000	2520	6005
Promissory Note	7.25%	365	147,000	10,658	147,000	2520	6005
Promissory Note	7.25%	365	172,348	12,495	172,348	2520	6005
Promissory Note	7.25%	365	902,490	65,431	902,490	2520	6005
TOTAL	**7.25%**		**5,585,838**	**404,973**	**5,585,838**		

Attachment 2 (of 2):

Affiliate Debt Terms: Shareholder Agreement

The terms of ORPC's affiliate debt are set out in section 13.0 of the attached agreement between ORPC and its shareholders. In the interests of transparency, ORPC is providing the complete agreement in this attachment.

THIS AGREEMENT made, in duplicate, this 01st day of October. 2000.

BETWEEN:

THE CORPORATION OF THE CITY OF PEMBROKE,

hereinafter called "Pembroke"

OF THE FIRST PART

- and -

THE CORPORATION OF THE VILLAGE OF BEACHBURG,

hereinafter called "Beachburg"

OF THE SECOND PART

- and -

THE CORPORATION OF THE TOWN OF MISSISSIPPI MILLS

hereinafter called "Mississippi"

OF THE THIRD PART

-and-

THE CORPORATION OF THE TOWN OF KILLALOE, HAGARTY & RICHARDS (formally KILLALOE HYDRO ELECTRIC COMMISSION)

hereinafter called "Killaloe"

OF THE FOURTH PART

-and-

OTTAWA RIVER POWER CORPORATION,

hereinafter called the "Corporation"

OF THE FIFTH PART

WHEREAS the Corporation was incorporated on the 29th day of April, 1999.

AND WHEREAS the Corporation's Articles of Incorporation provide that the Corporation is authorized to issue an unlimited number of common shares without par value and an unlimited number of special shares without par value.

AND WHEREAS the Corporation was incorporated for the purposes of distribution of electricity in and for the Province of Ontario.

AND WHEREAS Pembroke and Beachburg electric utilities amalgamated for the purposes of distribution of electricity in and for the Province of Ontario.

AND WHEREAS Pembroke and Beachburg received shares for a portion of the net book value of their assets at the time of the issuance of the shares and, also, security and interest with respect to the remaining net book value not allocated in shares.

AND WHEREAS as at the date hereof, Pembroke has been allocated 4,364 shares and Beachburg 147 shares of the Corporation.

AND WHEREAS it is in the interest of the parties hereto to amalgamate with other utilities in the County of Renfrew and in the County of Lanark for the efficient and effective distribution of electricity in the said counties.

AND WHEREAS the parties hereto have agreed with the valuation of their respective assets and have further agreed to the type of security interest with respect to the remaining net book value not allocated in shares and a method of calculating the interest on this debt.

AND WHEREAS the par value for each issued shares is based upon $ 1,000 per share.

AND WHEREAS it is anticipated that with the amalgamation with Killaloe and Mississippi, that Mississippi will be allocated approximately 839 common shares and Killaloe approximately 179 common shares (subject to adjustments as described in Paragraphs 4.0 and 19.0).

AND WHEREAS the Articles of Incorporation of the Corporation provide for restrictions on the transfer and ownership of shares.

AND WHEREAS the parties hereto agree that there shall be restrictions on the transfer of shares held by the shareholders.

AND WHEREAS the parties further agree that in the event that either of the parties wishes to sell its shares, that the other party or parties shall be entitled to the first right of refusal for same.

NOW THEREFORE in consideration of the mutual covenants and agreements contained herein, the parties agree as follows:

1.0 General

(a) Pembroke and Beachburg shall amalgamate their electrical distribution operations into the Corporation effective January 1st, 2000.

(b) Mississippi and Killaloe shall amalgamate their electrical distribution operations into the Corporation effective September 30th, 2000.

(c) The adjustment date shall be within ninety (90) days of the date of amalgamation, currently slated for September 30th, 2000. As a result, the adjustment date shall be on or before December 31st, 2000.

2.0 Shares holdings of Pembroke, Beachburg, Mississippi and Killaloe

(a) Pembroke is the owner of 4,364 shares of the Corporation and Beachburg is the owner of 147 shares of the said Corporation.

3.0 Adjustments

(a) Pembroke and Beachburg shall receive such further shares of the Corporation. as provided for pursuant to Paragraph 4.0 (Valuation) to recognize any additional equity in the Corporation.

(b) Mississippi and Killaloe shall receive shares of the Corporation based upon the December 31st, 1999 value of the assets being transferred into the Corporation and such additional shares pursuant to paragraph 4.0 (Valuation).

4.0 Valuation

(a) The parties acknowledge and agree that Pembroke and Beachburg, as existing shareholders of the Corporation received shares and security in the Corporation based on the net book value of the assets transferred to the Corporation by each shareholder. The parties further acknowledge and agree that shares and security to be received by Mississippi and Killaloe shall be determined by virtue of the net book value of the assets each shareholder contributes to the Corporation as at December 31st, 1999, as adjusted in accordance with paragraph 4.0 (h) to September 30th, 2000. One half of the net book value of the assets being transferred to the Corporation respectively by Mississippi and Killaloe shall be valued in shares issued to each of Mississippi and Killaloe respectively, based on $1,000.00 per share. These values, as of the date of this Agreement and based on December 31st, 1999 values, are as follows:

Mississippi Mills - 839,

Killaloe - 179.

The parties further agree that one half of the net book value of the assets to December 31st, 1999 shall be a debt owed by the Corporation to Mississippi Mills and Killaloe respectively.

(b) It is agreed that with respect to valuation of the amalgamating parties, the valuation of the assets of the parties shall be at net book value which, for the purposes of amalgamation, will be deemed to be fair market value. The parties. however, agree that net book value will only include receivables not greater than sixty (60) days past due billing and other assets will be recorded and accepted in accordance with the policy in the Accounting Procedures Handbook, Article 430.

(c) It is agreed that, as at the date of amalgamation, capital assets acquired up to that date will be recorded in the books of account of each of the amalgamating parties on the same basis as employed prior to December 31st, 1999.

(d) It is further agreed that each of the amalgamating parties will record depreciation in accordance with Accounting Procedures Handbook, Article 430 to the date of amalgamation.

(e) It is agreed that in order to recognize the additional equity, additional common shares and debt in the ratio of 50% share equity and 50% debt will be issued to each of the amalgamating parties as at the date of amalgamation. In the event that any of the parties acquired capital assets and issued debt, only the increase in net equity of the utility will be recognized and will be recognized in the books of account through the issuance of additional common shares and debt.

(f) It is agreed that the additional shares, as required will be issued and additional debt, as required, will be recorded not later than ninety (90) days after the effective date of amalgamation and will be based upon financial statements prepared as at the date of amalgamation. Each of the parties will have an opportunity to inspect the additional assets recognized above and will agree that the additional value will be recognized. In the event that agreement is not possible, then the parties will abide by the arbitration provisions as set out in this agreement.

(g) It is further agreed and understood that the aforementioned capital assets acquired after December 31, 1999 are not included in the "rate base" and accordingly there will be no earnings from which dividends nor interest can be paid during the initial three year term.

(h) It is further agreed that at the date of amalgamation, there will be a financial statement prepared which will record transactions in accordance with the Accounting Procedures Handbook. The Financial Statement will be prepared not later than ninety days (90) after the effective date of amalgamation. Any increase in net equity as a result of operations for the period of January 01, 2000 to the effective date of amalgamation will be recognized by the issuance of additional common shares and the recording of additional debt in the above ratio of 50% common shares and 50% debt of the Corporation. Any decrease in net equity as a result of operations for the period of January 01, 2000 to the effective date of amalgamation will be recognized by a reduction in common shares and a recording of the deduction of net in the above ratio of 50% common shares and 50% debt of the Corporation.

5.0 <u>Restrictions on transfer</u>

(a) Except as otherwise provided for herein, or specifically consented to in writing by the parties, the parties hereto shall not make any agreement to directly or indirectly sell, assign, transfer, give, devise, bequeath, mortgage, pledge, hypothec, or otherwise dispose of, alienate, or in anyway encumber or create a security interest in or grant any option on any of the shares in the capital of the Corporation they respectively own or may own for any purpose or reason whatsoever. Any attempt to accomplish or effect any or all of the acts prohibited hereby shall be null and void.

(b) Without restricting the generality of the foregoing, except with the consent of all of the shareholders, no shareholder shall sell or transfer any of its shares for a period of three years subsequent to this agreement.

6.0 Permitted Transfers

(a) At any time, and from time to time, any party may hypothecate, mortgage, pledge, charge or otherwise encumber or transfer to a creditor, all but not less than all of its shares as security for any loan or other indebtedness, but only on terms that should such creditor wish to realize all or part of such security, they shall comply with the provisions of Sections 7 and 8 hereof and offer the Shares to the other parties to this agreement.

7.0 Transfer to Wholly-Owned Subsidiary

(a) A shareholder shall be entitled to transfer all of its shares without consent at any time to an amalgamated corporation or entity of the Corporation, provided that at the time of such transfer, the said amalgamated entity enters into an agreement whereby the amalgamated body becomes bound by and entitled to the benefit of this Agreement.

8.0 Purchase by the Other Shareholders

(a) If any party hereto shall desire to dispose of all of its shares within ten (10) years of the execution of the agreement, it shall offer to sell its shares to the other parties hereto at 10% less than the fair market value of the shares at the time of sale. The fair market value of the shares shall be determined by agreement of the parties and if no such agreement can be arrived at, by the Corporation's accountants, and if a disagreement arises in that respect, then by arbitration as set out herein. Each of the other parties shall take all such offered shares in the same proportion as shares already owned and pay the sale price therefor within 30 days after the date the shares were offered for sale. Upon payment of the sale price for the shares so offered, the party offering the shares shall tender the resignation of its nominee as a director of the Corporation.

(b) The terms of the sale of the shares referred to in Section 8.0 (a) shall be in the same manner and on the same basis as provided for in the procedure set out in Section 9 subject to the valuation pursuant to Section 8.0 (a).

9.0 <u>Right of First Refusal</u>

(a) If any Shareholder (the "Offeror") shall desire or be obliged by law or otherwise to transfer into the name of some other person or persons or to sell or dispose of its shares after the period of ten (10) years as referred to in paragraph 8 herein or within that period in the event that no Shareholder agrees to purchase the shares as per the provisions of paragraph 8 herein then and in that event, subject to Paragraphs 7 and 8 herein, the other shareholders (the "Offeree") shall have the prior right to purchase the shares to be transferred on the terms and in accordance with the procedure contained in paragraph (b).

(b) The procedure on transfers is as follows:

(i) An Offeror shall give to the secretary of the corporation notice in writing of its desired intention to transfer, sell or otherwise dispose of any shares. The notice (the "Selling Notice") shall set out.

(A) the number of shares;

(B) the price and terms of payment which the Offeror is willing to accept for the Shares; and

(C) if the Offeror has received an offer to purchase the Shares, the name and address of the third party offeror and the terms of payment and price contained in the offer.

(ii) The secretary of the Corporation shall thereupon be deemed to be the agent of the Offeror for the purpose of offering the Shares to the Offerees on the terms of payment and for the price contained in the Selling Notice and the offer by the secretary shall remain open for acceptance as hereinafter provided for a period of thirty days following the making of the offer by the secretary.

(iii) All of the shares of the Offeror shall be offered by the secretary for sale to each Offeree as nearly as may be in proportion to the number of shares held by it as a proportion of all issued shares less any shares held by the Offeror. The offer shall state that any Offeree which desires to purchase shares offered in excess of its proportion shall state in its purchase notice (the "Purchase Notice") how many shares it desires to purchase in excess of its proportion. If, within the period of thirty days hereinbefore mentioned, a Purchase Notice has not been given by an Offeree to the secretary in respect of the Shares being offered, the Offeree shall be deemed to have refused to purchase the shares being offered.

(iv) If any Offeree does not claim its proportion of the shares being offered, the unclaimed shares shall be used to satisfy the claims of the Offerees in excess of their respective proportions. If claims in excess are more than sufficient to exhaust unclaimed shares being offered, the unclaimed shares shall be divided pro rata among the Offerees desiring such shares in excess of their proportion in proportion to the number of shares held by them at the date of the offer, provided that no Offeree shall be bound to take any shares in excess of the number it so desires.

(v) If the shares being offered shall not be capable of being offered to or divided among the Offerees as set forth above without resulting in division into fractions, the same shall be offered or divided among the Offerees as nearly as may be in accordance with the foregoing provisions and the balance shall be offered to or divided among the Offerees or some of them in such manner as may be determined by the Board.

(vi) If any of the shares being offered shall be accepted by any Offeree pursuant to the provisions of this paragraph (b), the shares being offered shall be sold to the Offeree for the price and for the terms contained in the Selling Notice.

(vii) In the event that no Offeree comes forward to purchase the shares offered within the time period as set out in Paragraph 9(b) (iii) herein, and the Offeror, upon marketing the said shares, receives an offer different than the offer set out in the selling notice then, in that event, the Offerees shall have thirty (30) days to purchase the said shares at a discounted price of 10% subject to the same terms and conditions set out in this paragraph.

(viii) If the Purchase Notices have not been given by the Offerees to purchase all of the shares being offered, the Offeror may, within sixty days after the expiration of the thirty-day period hereinbefore mentioned, offer and sell the unpurchased shares to any other person at the price and on the terms and conditions set out in the Selling Notice.

(c) No right created under paragraph (a) shall be exercised unless the approval in connection therewith under the *Investment Canada Act*, if any, has been obtained.

(d) The transfer of the shares shall be subject to the condition that the purchaser thereof shall, if not a party hereto, agree to be bound by the terms hereof and become a party hereto in accordance with the provisions of Section 14 and Section 17.

(e) If shares are being offered under paragraph (b) other than by reason of an obligation of law, the offer may be made only in respect of all (and not less than all) of the shares owned by the Offeror.

(f) If a sale, transfer or other disposition is completed in accordance with this section, the Offeror shall upon completion of the purchase be absolved from all liability to or in respect of the corporation under the provisions of this Agreement and the purchaser of the shares offered shall assume all obligations in respect thereof.

10.0 Allocation of Resources

(a) It is agreed by the parties that the Corporation shall establish and maintain a crew and office in the Town of Mississippi Mills for a minimum period of ten (10) years from the Effective Date. No changes shall be made to the location of the crew or office located in the Town of Mississippi Mills, including its abandonment, without the express approval of the nominee of Mississippi on the board of directors.

11.0 Review of Shareholdings

(a) It is agreed that the Board of Directors is required to review the respective shareholdings of the parties to this agreement and adjust fairly the respective amounts of shares and equity at the earlier of three (3) years from the date of execution of this agreement or on such earlier date and on the dates that the performance base rates are reviewed in and for the Province of Ontario.

(b) It is agreed that the review of the shareholdings, referred to in 11.0 (a) herein shall be brought up on the agenda of the Board of Directors as a mandatory item to be dealt with by the said Board on the occasions as set out in this heretofore referred to paragraph.

12.0 Employees of Mississippi

(a) It is agreed that Mississippi will provide to the Corporation, at no expense to the Corporation for a period of three (3) months following the execution of this agreement, the assistance of Brian Gallagher and Ray Clement to help and assist with the transfer of the distribution system and all billing services, computer networks, etc. for the Corporation.

(b) It is agreed that the Corporation will not use the services of the employee on a regular basis, but simply in an 'advisory capacity' when required by the Corporation during this interim period.

13.0 Promissory Note, Interest and Security for Debt

(a) The parties hereto agree that Pembroke, in exchange for one-half of the net book value of the assets, has, to this date, received a Promissory Note from the Corporation with the amount of the Promissory Note to be in the amount $ 4,364,000.00. Pembroke will be subject to any adjustment with respect to the Note, as set out in Paragraphs 4.0 (Valuation) and/or Paragraph 19.0 (Obligations of Shareholders)herein.

(b) The parties hereto further acknowledge and agree that Beachburg, in exchange for one-half of the net book value of its assets, has received a Promissory Note from the Corporation with the amount of the Promissory Note being in the amount of $ 147,000.00. Beachburg will be subject to any adjustment with respect to the Note, as set out in Paragraphs 4.0 (Valuation) and/or Paragraph 19.0 (Obligations of Shareholders) herein.

(c) The parties hereto agree that Mississippi Mills, in exchange for one-half of the net book value of its assets, will receive a Promissory Note from the Corporation with the amount of the Promissory Note to be $ 839,000.00 and any adjustment to the Note, as provided for in Paragraph 4.0 (Valuation) and/or Paragraph 19.0 (Obligations of Shareholders) herein.

(d) The parties hereto agree that Killaloe, in exchange for one-half of the net book value of its assets will receive a Promissory Note from the Corporation in the amount of $ 179,000.00 and any adjustment to the Note as provided for in Paragraph 4.0 (Valuation) and/or Paragraph 19.0 (Obligations of Shareholders) herein.

(e) The parties further agree that the Corporation shall pay interest on the Promissory Notes to Pembroke, Beachburg, Mississippi and Killaloe on their respective Notes in an amount not to exceed the maximum interest rate allowed by the Ontario Energy Board based upon their Handbook or any other regulation, schedule, document to be prepared or enacted by them or any successors to the said Ontario Energy Board or any other entity with regulatory authority for utilities in the Province of Ontario.

(f) The parties hereto agree that they may adjust the interest rate on the said Promissory Notes at the times and in the manner as set out by the regulation, and in an amount not to exceed the maximum interest rate allowed by any schedule, statute or otherwise as enacted by the Ontario Energy Board or any successor in the Province of Ontario.

(g) The parties hereto agree that the interest shall be calculated annually and paid quarterly to Pembroke, Beachburg, Mississippi and Killaloe respectively.

(h) The parties further agree that the Promissory Note will be for a period of twenty (20) years and shall be due and payable twenty (20) years after market opening, (which is currently slated for the 07th day of November, 2000). As such, the Note will be due and payable at the later of November 07th, 2020, or twenty (20) years after actual market opening.

(i) The parties further agree that the said Promissory Notes shall be non-interest bearing from the 01st day of January, 2000 to market opening, which is currently slated for the 07th day of November, 2000.

(j) The parties further hereto agree that in the event that Ottawa River Power Corporation is sold to a non-related entity or otherwise disposed of, the

Promissory Note, principal and any accrued interest shall at the option of the noteholder be payable to Pembroke, Beachburg, Mississippi and Killaloe in their respective amounts at the time of such sale or disposition.

(k) The parties further agree that, should any interest payments fall due prior to the final completion of all the Transfer By-Laws and necessary documents to effect the transfer of the assets from Pembroke, Beachburg, Mississippi, Killaloe or any other necessary approvals, such as OEB, such interest payments shall be deemed due thirty (30) days after all necessary revisions of this agreement are complete and OEB and all necessary approvals are obtained. Such deferral payments shall not be deemed as default.

14.0 Board of Directors of Corporation

(a) Appointment and Replacement - The Board of Directors of the Corporation shall consist of at least one director from each Municipality.

(b) Remuneration - Directors of the corporation shall be remunerated as such for their work and services to the Corporation, and the Corporation shall bear all costs (including costs of transportation and lodging, if any) of the attendance at all meetings of the Board by the director nominated to the board by such shareholder.

(c) Appointment and Replacement - Except as they may otherwise agree in writing in accordance with the terms hereof, the parties hereto agree that:

(i) the board of the Corporation will consist of seven (7) directors;

(ii) all voting rights in respect of the shares shall be exercised for the election and maintenance in office as directors of four (4) nominees of Pembroke, one (1) nominee of Beachburg, one (1) nominee of Mississippi and one nominee of Killaloe;

(iii) the number of directors from time to time constituting a quorum at the meetings of the Board shall be a majority of the directors, provided that at least two directors nominated by Pembroke be present and at least two other directors nominated by Beachburg, Mississippi and/or Killaloe be present.

(iv) on the appointment or election of each director, the secretary of the corporation shall make note of the nominator of the director in the records of the corporation and the nominator shall be entitled by direction in writing, from time to time, to remove its nominee or nominees and to nominate his successor or successors who shall promptly be elected a director as contemplated herein;

(v) resolutions shall be decided by a majority of those voting;

(vi) subject to the provisions with respect to recorded votes, the chairman of the meeting shall have a second or casting vote;

(vii) all of the persons from time to time nominated to the Board by A shall be resident Canadians, as such term is defined in the *Business Corporations Act* of Ontario.

15.0 Officers

(a) Appointment - Until changed by resolution of the Board, the officers of the Corporation shall maintain the following positions:

Office
Chairman of the Board
President
Vice-President
Secretary-Treasurer

(b) Remuneration - Officers of the Corporation shall be remunerated as such for their work in and services to the Corporation, and the Corporation shall reimburse them for all of their out-of-pocket expenses incurred in performing their duties, including reasonable costs for transportation and lodging, save and except if an employee or independent contractor of the Corporation or as a proxy to a shareholder, is an officer of the Corporation, in which case out of pocket expenses only shall be reimbursed by the Corporation to the shareholder on behalf of which such officer is acting.

16.0 Restrictions on management of the Corporation

(a) Unanimous approval - Except with the written consent of each of the parties to this agreement, no action will be taken by the directors and/or officers on behalf of the Corporation or with respect to any of the following:

(i) changing the provisions in the by-laws of the Corporation;

(ii) the sale of all or substantially all of the properties and assets of the corporation;

(iii) issuance of any new shares of the Corporation, except for the purposes of allowing the entry of member shareholders of other municipal electrical utilities;

(iv) the dissolution or winding up of the Corporation.

(b) Special approval - except with the written consent of the parties to this Agreement that are the holders of 80% of the aggregate number of shares outstanding at such time, no action will be taken by the directors and/or officers on behalf of the Corporation or with respect to any of the following:

(i) the declaration or payment of any dividend, distribution or bonus to employees;

(ii) the acquisition or disposition by the Corporation of interests in other enterprises;

(iii) the purchase, sale, mortgage or lease by the Corporation of any real property;

(iv) any purchase, commitment, lease or expenditure which, if completed, would raise the aggregate of capital expenditures of the Corporation in any fiscal year to more than $3 million adjusted by inflation in each year; with the base year for inflation calculation purposes being the year 2000.

(v) the employment of any person at an aggregate (including benefits) annual remuneration of more than or equal to $100,000.00 per year or an increase in the remuneration of any employee to a total in excess of that amount, with the base year for inflation calculation purposes being the year 2000.

(vi) the lending of money by the Corporation in any year in excess of $100,000.00, except to an affiliate corporation.

(vii) any commitment by the corporation which raises the aggregate of the outstanding obligations of the corporation for material or supplies (excluding the cost of power and labour) at any one time in a fiscal year to more than $1.5 million adjusted by inflation, with the base year for inflation calculation purposes being the year 2000.

(viii) the authorization or execution by the Corporation of any contract, the performance of which by the Corporation will require more than three (3) years and calls for a contractual amount in excess of $200,000.00 with the exception of the Hydro Pontiac Operating Agreement and with the exception of any contract with any power suppliers, with the base year for inflation calculation purposes being the year 2000.

(ix) the guarantee by the corporation of the debts of any other person in any amount;

(x) the approval of the audited Financial Statements of the Corporation;

(xi) the amendment of the signing authority relating to the corporation's bank accounts;

(xii) any action or transaction not in the ordinary course of the business of the Corporation; or

(xiii) the issuance of new shares of the Corporation for the purposes of allowing the entry of member shareholders of other municipal electrical utilities.

17.0 **Voting Powers**

(a) The parties hereto shall at all times use their voting powers (whether expressed by way of vote or written consent) in accordance with the provisions of this Agreement and for the purposes of effectuating the same and for the purposes of ensuring that the directors of the Corporation shall exercise their powers as members of the Board consistently with the provisions of this Agreement and for the purposes of effecting the same. The Board shall see to it that the officers and employees of the Corporation carry out all duties which they are required to perform under the provisions of this Agreement.

18.0 **Additional Parties**

(a) Every issue and transfer of shares shall be subject to the condition that each subscribed or transferee, as the case may be, shall, if not a party hereto, agree to be bound by the terms hereof and become a party hereto by executing an agreement to be bound hereby. Any agreement to be bound hereby and any other agreement in favour of the parties hereto shall be effectively delivered to each party hereto by delivering to the secretary of the Corporation a signed copy thereof and the secretary shall thereupon forward a photocopy of such copy to each party hereto.

19.0 **Obligations of Shareholders**

(a) Each of the shareholders to this agreement referred to herein shall be responsible for costs incurred to effect the Corporation and the work performed with respect to the corporation which costs shall include:

(i) the costs of incorporation;

(ii) the drafting of the necessary by-laws for the Corporation;

(iii) the Shareholder's Agreement;

(iv) the Transfer By-law;

(v) the costs of accountants incurred for the Corporation.

(b) The parties hereto agree that any shareholder may pay for these expenses, either in cash or by a reduction in its issued shares valued at net book value, reduced by its proportionate cost in the Corporation. This cost may be adjusted as new municipalities become shareholders in the Corporation.

20.0 Objects of the Corporation

(a) The parties hereto agree that the shareholders, the officers and directors and parties hereto agree that the Corporation is incorporated to distribute power and that the parties and all the shareholders and directors and officers hereto are obligated to comply with all the provisions, terms and obligations as set out in the corporation documents and restrictions in their objects and must carry out the objects of the Corporation which requires such distribution on supply of power. It is agreed by all parties that all service areas covered by the municipalities who are shareholders of the Corporation shall be treated similarly and with equality.

(b) In the event that any disagreement arises between the parties hereto with reference to this agreement, or any matters arising hereunder, and upon which the parties cannot agree then every such disagreement shall be referred to arbitration pursuant to provisions of the Arbitrations Act, R.S.O. 1990, Chapter A.24 and in accordance with the provisions of the following:

(i) The reference to arbitration shall be to three (3) arbitrators, one of whom shall be chosen by each party to the disagreement and the third by the two so chosen and the third arbitrator so chosen shall be the chairman; provided, however, that if the parties are able to agree upon a single arbitrator, the reference to arbitration shall be to that single arbitrator.

(ii) The award may be made by the majority of the arbitrators.

(iii) If the arbitrators have allowed their time or extended time for making an award, as provided in the Arbitrations Act, to expire without making an award or if the Chairman shall have delivered to the parties to the arbitration a notice in writing stating that the arbitrators cannot agree, any party to the arbitration may apply to the Superior Court of Justice or to a judge thereof to appoint an umpire who shall have the like power to act in the reference and to make an award as if he had been duly appointed by all the parties to the submission and by the consent of all the parties who originally appointed the arbitrators thereto.

(iv) If an umpire is appointed pursuant to the foregoing, such umpire shall make his award within one month after the original or extended time appointed for making the award of the arbitrators has expired on or before any later date to which the parties to the reference by a writing signed by them may from time to time enlarge the time for making the award, or if such parties have not agreed, then within such time as the Court or judge appointing such arbitrator may deem proper.

(v) There shall be no appeal from the award of the arbitrator or arbitrators in accordance with the provisions of the Arbitrations Act.

21.0 Amendment of Agreement

(a) This agreement may be amended or altered in any of its provisions and such changes shall become effective when reduced to writing and signed by the parties hereto.

22.0 Termination of Agreement

(a) This agreement shall terminate on the occurrence of any of the following:

i) written agreement of the parties hereto;

ii) bankruptcy, receivership or dissolution of the Corporation.

23.0 Binding on Heirs and Others

(a) This agreement shall be binding not only on the parties hereto, but also upon their heirs, executors, administrations or assigns and the parties hereto or any amalgamated corporations that may be amalgamated in the future in the Province of Ontario with the corporations referred to herein, agree for themselves, their heirs, executors, administrators or assigns to execute any instruments which may be necessary or proper to carry out the purpose and intent of this agreement.

24.0 **Notices**

(a) All notices, demands, requests, consents and approvals which may or are required to be given or made pursuant to any provision of this Agreement shall be given or made in writing and shall be served personally or mailed by prepaid and registered mail, in the case of:

Corporation of the City of Pembroke, 1 Pembroke Street East, Box 277, Pembroke, Ontario, K8A 6X3.

Corporation of the Village of Beachburg, Beachburg, Ontario, K0J 1C0.

Corporation of the Town of Mississippi Mills, 28 Mill Street, P.O. Box 179, Almonte, Ontario, K0A 1A0.

Corporation of the Township of Killaloe, Hagarty and Richards (formally Killaloe Hydro Electric Commission), 1 John Street, Box 39, Killaloe, Ontario, K8J 2A0.

Ottawa River Power Corporation, PO Box 1087, Pembroke, Ontario K8A 6Y6.

or to such other addresses as the parties may from time to time advise the other parties hereto by notice in writing. The date of receipt of any such notice, demand or request shall be deemed to be the date of delivery of such notice, demand or request if served personally, or if mailed as aforesaid, the third day of business following the date of such mailing.

25.0 The invalidity of any provision of this Agreement or any covenant herein contained on the part of any party shall not affect the validity of any provision or covenant hereof or herein contained.

26.0 This agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

27.0 Time shall be of the essence of this Agreement.

IN WITNESS WHEREOF the parties hereto have hereunto set their hands and seals on the date first above written.

SIGNED, SEALED AND DELIVERED in the presence of	**THE CORPORATION OF THE CITY OF PEMBROKE**
	THE CORPORATION OF THE VILLAGE OF BEACHBURG
	Phyllis McEnroe
	THE CORPORATION OF THE TOWN OF MISSISSIPPI MILLS
	Paul F. Finnie

)
)
) THE CORPORATION OF THE
) TOWNSHIP OF KILLALOE, HAGARTY
) AND RICHARDS (formerly KILLALOE
) HYDRO ELECTRIC COMMISSION
)
)
) Isabel O'Reilly
)
)
)
) Lorne Dhadin
)
) OTTAWA RIVER POWER
) CORPORATION,
)
)
) President

Exhibit 6:

REVENUE DEFICIENCY OR SUFFICIENCY

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 1 (of 2): Utility Revenue

REVENUE FROM EXISTING RATES

Projected revenues in 2010 based on existing rates, which are used in calculating utility income, are comprised of distribution revenue and other revenues.

Distribution revenue at existing rates is presented in Exhibit 3, Tab 2. Other revenue is presented in Exhibit 3, Tab 3.

OVERVIEW OF REVENUE REQUIREMENT

Attachment 1 shows the proposed revenue requirement for the 2010 test year.

The total Service Revenue Requirement is comprised of the following:

- Projected distribution expenses in 2010:
  - OM&A (Operations, Maintenance and Administration) expenses, as described in Exhibit 4, Tab 1, Schedule 2; and
  - Amortization expense, as shown in Exhibit 4, Tab 7, Schedule 1, Attachment 1;
- Regulated Return on Capital, as shown in Exhibit 5, Tab 1, Schedule 1, Attachment 1; and
- The proposed Allowance for PILs in 2010, as described in Exhibit 4, Tab 8, Schedule 3.

The proposed Base Revenue Requirement, representing the revenue to be recovered from base distribution rates, is equal to the total Service Revenue Requirement, less Revenue Offsets derived from other revenue sources in 2010. The Revenue Offsets are shown in Exhibit 3, Tab 3, Schedule 4, Attachment 1.

Distribution Revenue Requirement

		2010 Projection
OM&A Expenses	*from sheet D1*	2,570,853
3850-Amortization Expense	*from sheet E2*	791,805
Total Distribution Expenses		3,362,658
Regulated Return On Capital	*from sheet D3*	931,001
PILs (with gross-up)	*from sheet E4*	56,851
Service Revenue Requirement		**4,350,510**
Less: Revenue Offsets	*from sheet C9*	377,968
Base Revenue Requirement		**3,972,542**

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 2 (of 2): Deficiency or Surplus

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

Attachment 1 presents the calculation of the revenue deficiency for the 2010 test year.

Utility Income represents Total Net Revenues, less expenses for OM&A, Depreciation & Amortization, and PILs. Total Net Revenues is comprised of projected distribution revenues at existing rates (see Exhibit 3, Tab 2, Schedule 1, Attachment 1) and revenue offsets. The following table indicates the references within the application for these amounts:

Table 1: Utility Income References

Total Net Revenues:	
Distribution Revenues	Exhibit 3, Tab 2, Schedule 1, Attachment 1
Revenue Offsets	Exhibit 3, Tab 3, Schedule 4, Attachment 1
Expenses:	
OM&A	Exhibit 4, Tab 1, Schedule 2
Depreciation & Amortization	Exhibit 4, Tab 7, Schedule 1, Attachment 1
PILs	Exhibit 4, Tab 8, Schedule 3, Attachment 1[1]

The Indicated Rate of Return is equal to Utility Income divided by the Rate Base amount. Attachment 2 presents the statement of rate base, consistent with the information in Schedule 2, Tab 1. The Requested / Approved Rate of Return for 2010 appears on the last page of Exhibit 5, Tab 1, Schedule 1, Attachment 1. The Indicated Rate of Return is less than the Requested / Approved Rate of Return, therefore there is a Deficiency in Return. The Net Revenue Deficiency is the Deficiency in Return, multiplied by the Rate Base amount.

The Provision for PILs/Taxes is the difference between the PILs amount appearing in the calculation of Utility Income, and the proposed Allowance for PILs as shown in Exhibit 6, Tab 1, Schedule 2, Attachment 1. The sum of the Net Revenue Deficiency and the Provision for PIL/Taxes yields the Gross Revenue Deficiency.

[1] see sheet P8, ‘2010 Projection’ (at existing rates)

The Deemed Overall Debt Rate and Deemed Cost of Debt appear on the last page of Exhibit 5, Tab 1, Schedule 1, Attachment 1. The Return on Deemed Equity is derived by taking Utility Income, less the Deemed Cost of Debt, divided by the equity capitalization amount (which also appears on the last page of Exhibit 5, Tab 1, Schedule 1, Attachment 1).

Table of Revenue Deficiency or Surplus

		2010 Projection
Utility Income	*(see below)*	570,051
Utility Rate Base		11,518,294
Indicated Rate of Return		4.95%
Requested / Approved Rate of Return		8.08%
Sufficiency / (Deficiency) in Return		(3.13%)
Net Revenue Sufficiency / (Deficiency)		**-360,950**
Provision for PILs/Taxes		-56,851
Gross Revenue Sufficiency / (Deficiency)		**-417,801**
Deemed Overall Debt Rate		*6.90%*
Deemed Cost of Debt		*477,180*
Utility Income less Deemed Cost of Debt		*92,871*
Return On Deemed Equity		*2.02%*
UTILITY INCOME		
Total Net Revenues		3,932,709
OM&A Expenses		2,600,768
Depreciation & Amortization		791,805
Taxes other than PILs / Income Taxes		-29,915
Total Costs & Expenses		3,362,658
Utility Income before Income Taxes / PILs		570,051
PILs / Income Taxes		
Utility Income		**570,051**

Statement of Rate Base

	2006 EDR Approved	2010 Projection
Net Capital Assets in Service:		
Opening Balance		8,553,872
Ending Balance		8,858,732
Average Balance	8,408,527	8,706,302
Working Capital Allowance *(see below)*	2,351,008	2,811,992
Total Rate Base	**10,759,535**	**11,518,294**

Expenses for Working Capital

Eligible Distribution Expenses:		
3500-Distribution Expenses - Operation	368,413	360,476
3550-Distribution Expenses - Maintenance	298,526	705,409
3650-Billing and Collecting	459,406	616,443
3700-Community Relations	51,448	58,624
3800-Administrative and General Expenses	970,222	859,815
3950-Taxes Other Than Income Taxes		-29,915
Total Eligible Distribution Expenses	2,148,015	2,570,853
3350-Power Supply Expenses	13,525,374	16,175,760
Total Expenses for Working Capital	15,673,389	18,746,614
Working Capital factor	15.0%	15.0%
Working Capital Allowance	**2,351,008**	**2,811,992**

CAUSES OF REVENUE DEFICIENCY OR SURPLUS

ORPC's existing rates are based on the Board-approved rates in 2006 following a cost of service rate application, and adjustments to its base distribution rates in 2007-09 under the Board's Second Generation Incentive Regulation Mechanism ("2GIRM"). Price cap adjustments of 0.9%, 1.1% and 1.3% were applied in 2007, 2008 and 2009, respectively, in the 2GIRM rate applications approved by the Board. As a result, current base distribution rates reflect an aggregate price cap of adjustment of 3.3% relative to the 2006 Board-approved rates.

Projected customer connections for 2010 are 3.1% higher than those approved in setting 2006 distribution rates; however, projected load is lower: kWh's decreased by 4.1% and kW's decreased by 5.3%. The combined effect of the aggregate price cap adjustment and volume changes causes an increase of about 3% in base distribution revenue.

As shown in Attachment 1 to the previous schedule, the Net Revenue Deficiency (excluding PILs) is $361K.

The deficiency is due primarily to increased expenses for Operations, Maintenance and Administration (OM&A). Projected OM&A for 2010 is $423K higher than the 2006 Board-approved amount, an increase of 20%. The cost drivers underlying this increase are presented in Exhibit 4, Tab 2, Schedule 1, Attachment 3.

The increase in the rate base is another cause of the revenue deficiency. The proposed rate base for 2010 is $759K higher than the 2006 Board-approved amount, an increase of 5%. Based on an 8.08% overall cost of capital,[1] the increase in the rate base drives a $61K increase to the revenue requirement. The factors contributing to the change in the rate base are discussed in Exhibit 2, Tab 1, Schedule 2.

[1] Exhibit 5, Tab 1, Schedule 1, Attachment 1, page 5

Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 1): Cost Allocation

OVERVIEW OF COST ALLOCATION

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the “Directions”). On November 15, 2006, the Board issued the Cost Allocation Model (the “Model”) and User Instructions (the “Instructions”) for the Model.

ORPC engaged Elenchus Research Associates (“Elenchus”) to complete its cost allocation models for this application, with different versions used to reflect the 2006 Board-approved information and the proposed 2010 test year data, all prepared in accordance with the Directions, Instructions, and section 2.8 of the Board’s Filing Requirements for Distribution and Transmission Applications. The Elenchus report is included as Attachment 1 to this schedule, and the model files referenced therein have been submitted to the Board in electronic form. This report addresses Cost Allocation based on previously approved rates. ORPC’s proposed revenue allocation and the resulting Revenue-to-Cost ratios are discussed in Schedule 2 of this Exhibit/Tab.

Attachment 1 (of 1):

Cost Allocation Study Report

Ottawa River Power Corporation
2010 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Ottawa River Power Corporation

June 2010

elenchus

Table of Contents

1 INTRODUCTION

Ottawa River Power Corporation ("ORPC") has prepared its 2010 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the May 27, 2009 update to the document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements").

Section 2.8 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must*
>
> - *reflect future loads and cost and be supported by appropriate explanations;*
> - *be corrected for transformer ownership allowance ..., and*
> - *be presented in the form of an Excel spreadsheet.*[1]

The Filing Requirements also state that:

> *The Board expects the filings made by the applicant will follow the cost allocation policies reflected in the Board's report of November 28, 2007, Application of Cost Allocation for Electricity Distributors (EB-2007-0667).*

ORPC asked Elenchus Research Associated (Elenchus)[2] to assist it by preparing an appropriate cost allocation study for its 2010 cost of service rate application. In addressing this issue, Elenchus was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors".[3]

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[1] *Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009,* p. 19.

[2] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by ORPC and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

[3] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.*

The "influencing factors" discussed in section 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5)
- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6)
- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

> *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (p. 6)*

In utilizing the Board's cost allocation model for ORPC's 2010 cost allocation study, Elenchus has been cognizant of these "influencing factors" as they apply to ORPC. In particular, ORPC has an amortization expense adjustment, which represents the difference between the expense amount and the change to accumulated amortization in 2010. This difference is due to (i) depreciation of vehicles and tools charged out to projects and (ii) depreciation of contributed capital, which is netted in account *1995-Contributions and Grants – Credit*, rather than included in accumulated amortization. For Cost Allocation, this $173,265 adjustment was captured in account *5730-Amortization of Unrecovered Plant and Regulatory Study Costs*, and was allocated using the allocator for Operating and Maintenance expenses.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study ("CA Study") is to determine the proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2010 test year can be based on an allocation of the 2010 test year costs (i.e., the 2010 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.
- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In the case, the CA Study will rely on actual costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2010 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2010 revenue requirement to the various classes.

The ORPC CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered over the past two years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2010 loads than 2008 loads during the next IRM cycle.

1.2 ORPC'S 2006 COST ALLOCATION INFORMATION FILING

ORPC filed its 2006 Cost Allocation Information Filing ("CAIF") on May 09, 2007, using 2004 financial information. ORPC's 2006 CAIF relied on the Board's 2006 Cost Allocation Model ("CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the ORPC CA Study, explaining each of the model runs (or version of the CA model) included in the study, as well as the load and cost information used for each run. Section 3 explains the methodology used to develop the 2010 ORPC model by documenting each step taken in completing the model. Section 4 summarizes the results of the ORPC CA Study, showing the class revenue requirements and revenue to cost ratios generated by each version of the CA models.

2 OVERVIEW OF THE ORPC 2010 CA STUDY

2.1 MODELS RUNS INCLUDED IN THE ORPC COST ALLOCATION STUDY

Section 2.8.3 of the updated Filing Requirements specifies that "three sets of revenue to cost ratios for each customer class" must be provided based on:

- "the initial cost allocation model" which is the 2006 cost allocation information filing ("CAIF");
- "the initial cost allocation model revised with the adjusted transformer ownership allowance" which is the 2006 cost allocation information filings, adjusted in accordance with section 2.8.2 of the updated Filing Requirements; and
- "the updated cost allocation model" which is the appropriate 2010 model.

Hence, the cost allocation studies prepared for purposes of all 2010 cost of service filings must include these three separate CA models. As a result, the ORPC Cost Allocation Study ("CA Study") consists of three versions of the OEB's cost allocation model. For clarity, the following designations are used.

- **ORPC-2006: ORPC 2006 Model**: The ORPC CAIF as filed in 2006.
- **ORPC-2006C: ORPC 2006 Model Corrected**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements.
- **ORPC-2010: ORPC 2010 Model**: The 2006 CAIF with the corrected treatment of the Transformer Ownership Allowance and 2010 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "the updated model must be consistent with the load forecast and costs in the test year ... If updated load profiles are not available, the load profiles of the classes may be the same as those used in the information filing scaled to match the load forecast." (Section 2.8.1, pp. 19-20)

The ORPC 2010 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2010 load forecast and customer counts by class being used by ORPC in its application were also used for the 2010 CA models. ORPC's load forecast was prepared by Elenchus.
- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF was used for all classes.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2010 models for the following reasons.

1. Elenchus explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of ORPC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.

4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.

5. The 2006 hourly load profiles were based on 2004 actual loads and updated hourly load profiles would be based on 2008 actual loads. An update of the hourly load profiles after only 4 years (2004 to 2008) can be expected to produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs based on the 2006 CA Model methodology. (The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time.)

6. There are no Intermediate or Large User customers in the ORPC service area.

2.3 COST INFORMATION

As noted earlier, Elenchus's preferred methodology for preparing 2010 cost allocation models is to use the prospective 2010 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2010 test year. In the case of ORPC, the financial information for the forecast year has been prepared at the USoA level consistent with the level of detail embedded in the OEB's cost allocation model.[4]

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[4] Some information (i.e., meter counts and some amortization detail) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the ratio of meters to customers was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

3 ORPC COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus's methodology for the ORPC Cost Allocation Study which includes the 2006 models and the 2010 CA Model.

The uncorrected 2006 CAIF model (XX-2006) is an unaltered version of the model that was filed with the Board in 2007. The corrected 2006 ORPC CA Model (ORPC-2006C) was corrected using the methodology set out in section 2.8.2 of the Filing Requirements.

3.1 2010 ORPC CA MODEL

3.1.1 HOURLY LOAD PROFILE (HONI FILE)

For the ORPC CAIF, HONI provided data files with three worksheets that were used as input to the 2006 CAIF:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.
- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The ORPC hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2010. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2010 load forecast while maintaining the hourly load shapes.

3.1.2 Demand Allocators (HONI File)

The demand allocators used in the ORPC-2010 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2010 hourly load profiles resulting from the preceding step. Using the 2010 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2010 Demand Data (ORPC-2010 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2010 ORPC CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50, Street Light, and Sentinel are not equal to the full class NCP values since not all customers use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

3.1.4 2010 Customer Data (ORPC-2010 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was replaced with the 2010 load forecast in the 2010 CA Model.

In addition, the demand data (kW and kWh) in rows 21, 22, 25, and 56 of Sheet I6 Customer Data were replaced with the forecasted values. Row 23 was scaled by the percentage change in row 22.

The 2010 Distribution Revenue in row 29 was derived using the forecast demand (kW and kWh) and customer counts by rate class and the existing 2009 rates.

3.1.5 2010 Revenue to Cost Ratios

Since ORPC is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2010. The 2010 total revenue to cost ratio at current rates is less than 100% by the amount of the required rate increase. The revenue to cost ratios of the classes reflect the costs allocated to the classes based on the OEB CA Model methodology and the revenues that would be generated at current rates given the forecast demand (kW and kWh) and customer counts by rate class for 2010.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the ORPC cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	ORPC-2006	ORPC-2006C	ORPC-2010	Board Target Range
Residential	109.80	111.21	94.45	85-115
GS < 50 kW	87.56	88.27	77.46	80-120
GS > 50 kW	108.51	103.43	113.52	80-180
Street Lighting	29.16	30.03	25.59	70-120
Sentinel Lighting	45.78	47.17	39.24	70-120
USL	4.88	4.97	286.82	80-120
Total	100.00	100.00	90.40	

Note that the total revenue to cost ratio for ORPC-2010 is less than 100% because it represents the revenue to cost ratios for 2010 at current rates. At proposed rate the total revenue to cost ratio would be 100%. In addition, ORPC's proposed rates for 2010 will alter the relative revenue to cost ratios of the classes.

The ORPC-2010 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2010 forecast test year.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	ORPC-2006		ORPC-2006C		ORPC-2010	
	$	%	$	%	$	%
Residential	1,898,558	51.55	1,874,425	51.54	2,387,171	54.87
GS < 50 kW	863,292	23.44	856,332	23.55	931,945	21.42
GS > 50 kW	720,447	19.56	711,380	19.56	759,850	17.47
Street Lighting	180,851	4.91	175,565	4.83	242,824	5.58
Sentinel	16,491	0.45	16,007	0.44	20,565	0.47
USL	2,980	0.08	2,927	0.08	8,154	0.19
Total	3,682,619	100.00	3,636,636	100.00	4,350,510	100.00

REVENUE ALLOCATION AND REVENUE-TO-COST RATIOS

The following table shows the Revenue to Cost ratios by rate class from the 2006 EDR Cost Allocation model (as corrected for the treatment of transformer allowances), ORPC's proposed target ratios and the Board-prescribed ranges for these ratios:

Table 1: Proposed Target Revenue to Cost Ratios

	2006 EDR	Target	Prescribed Range	Total Bill Impact
Residential	1.11	1.07	0.85 – 1.15	-14.3%
GS < 50 kW	0.88	0.88	0.80 – 1.20	-8.7%
GS 50-4,999 kW	1.03	1.03	0.80 – 1.80	-10.7%
USL	0.05	0.80	0.80 – 1.20	-38.6%
Sentinel Lighting	0.47	0.70	0.70 – 1.20	+2.2%
Street Lighting	0.30	0.70	0.70 – 1.20	+35.9%

Revenue to Cost ratios for Unmetered Scattered Load (USL), Sentinel Lighting and Street Lighting were below the applicable prescribed range. ORPC proposes to move these ratios to the applicable floor boundary.

ORPC proposes to maintain the existing Revenue to Cost ratios for the General Service classes, which were within the applicable prescribed range. The ratio for the Residential class was also within the prescribed range; ORPC proposes to reduce this ratio within this range. Since the Residential class had the highest revenue to cost ratio, it was selected to offset ratio increases in other classes.

The above table also shows that to achieve the target Revenue to Cost ratios in 2010 rates, the total bill increase for Street Lighting would exceed the 10% threshold. ORPC therefore proposes to phase in the increase to its Revenue to Cost ratio over four years.

In previous decisions on cost of service applications for electricity distributors, the Board has ordered that where the Revenue to Cost ratio for a rate class was well below the applicable prescribed range, the ratio should move halfway to the floor boundary in the

Test year, with the outstanding gap to be closed over the following one or two years of the Incentive Regulation period. However, this approach would result in a total bill increase in 2010 of more than 10% for Street Lighting.

ORPC therefore proposes to increase the Revenue to Cost ratio for Street Lighting in equal increments over a period of four years to reach the range floor. The following table demonstrates the effect of this proposed approach and the resulting total bill impacts in the Test year:

Table 2: Impact of Moving 25% to Target Ratio for Street Lighting in the Test Year

	2006 EDR	Target	2010 EDR	Total Bill Impact
Residential	1.11	1.07	1.10	-13.4%
GS < 50 kW	0.88	0.88	0.88	-8.7%
GS 50-4,999 kW	1.03	1.03	1.03	-10.7%
USL	0.05	0.80	0.80	-38.6%
Sentinel Lighting	0.47	0.70	0.70	+2.2%
Street Lighting	0.30	0.70	0.40	+8.0%

ORPC would phase in changes to Revenue to Cost ratios as follows over the Incentive Regulation period:

Table 3: Proposed Changes to Revenue to Cost Ratios

	2006 EDR	2010 EDR	2011	2012	2013
Residential	1.11	1.10	1.09	1.08	1.07
GS < 50 kW	0.88	0.88	0.88	0.88	0.88
GS 50-4,999 kW	1.03	1.03	1.03	1.03	1.03
USL	0.05	0.80	0.80	0.80	0.80
Sentinel Lighting	0.47	0.70	0.70	0.70	0.70
Street Lighting	0.30	0.40	0.50	0.60	0.70

Attachment 1 to this schedule shows the results of the proposed Revenue to Cost ratios on the allocation of Test Year revenues. Attachment 2 summarizes the Revenue to Cost ratios. Attachment 3 shows the Test Year revenue impacts of the changes to Revenue to Cost ratios.

Table of Allocation Results

Customer Class Name	Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $ [3]			Directly Assigned Revenues [3]	Total Base Revenue Requirement
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application		
Residential	54.78%	56.23%	60.73%	2,176,217	2,233,951	2,412,448		2,412,448
General Service Less Than 50 kW	21.24%	17.77%	18.51%	843,938	705,999	735,366		735,366
General Service 50 to 4,999 kW	17.64%	23.97%	18.29%	700,768	952,274	726,603		726,603
Unmetered Scattered Load	0.19%	0.61%	0.15%	7,551	24,387	5,920		5,920
Sentinel Lighting	0.48%	0.18%	0.32%	19,055	7,130	12,885		12,885
Street Lighting	5.66%	1.23%	2.00%	225,013	48,801	79,319		79,319
TOTAL	**100.00%**	**100.00%**	**100.00%**	**3,972,542**	**3,972,542**	**3,972,542**		**3,972,542**

[1] *Revenue shares based on 2010 Cost Allocation model*
[2] *Revenue shares based on existing distribution rates*
[3] *%s applied to Base Revenue Requirement*

Customer Class Name	Service Revenue Requirement			Cost Allocation	Variance	Target Range	
	Allocated Revenue [8]	Allocated Cost [8]	Revenue to Cost Ratio	Revenue to Cost Ratio [9]		Floor	Ceiling
Residential	2,623,403	2,387,171	1.10	1.11	-0.01	0.85	1.15
General Service Less Than 50 kW	823,374	931,945	0.88	0.88	0.00	0.80	1.20
General Service 50 to 4,999 kW	785,685	759,850	1.03	1.03	-0.00	0.80	1.80
Unmetered Scattered Load	6,523	8,154	0.80	0.05	0.75	0.80	1.20
Sentinel Lighting	14,395	20,565	0.70	0.47	0.23	0.70	1.20
Street Lighting	97,130	242,824	0.40	0.30	0.10	0.70	1.20
TOTAL	4,350,510	4,350,510	1.00	1.00			

[8] *Base Revenue Requirement (per first table above), plus Miscellaneous Revenues (per sheet F3)*
[9] *from 2006 EDR Cost Allocation model (as revised for transformer allowances)*

Revenue-to-Cost Ratios

Customer Class	(1) From 2006 EDR Cost Allocation Model	(2) Column 1 Revised (Transformer Ownership Allowance)	(3) Proposed for Test Year	(4) Board Target Range
Residential	1.10	1.11	1.10	0.85 - 1.15
General Service Less than 50kW	0.88	0.88	0.88	0.80 - 1.20
General Service 50 to 4,999 kW	1.09	1.03	1.03	0.80 - 1.80
Unmetered Scattered Load	0.05	0.05	0.80	0.80 - 1.20
Sentinel Lighting	0.46	0.47	0.70	0.70 - 1.20
Street Lighting	0.29	0.30	0.40	0.70 - 1.20

Test Year Revenue Impacts

Customer Class	Base Revenue at Existing Rates (see below)	Base Test Year Revenue Assuming Current Revenue to Cost Ratios *	Base Test Year Revenue Assuming Proposed Revenue to Cost Ratios *
Residential	2,043,761	2,233,951	2,412,448
General Service Less than 50kW	633,839	705,999	735,366
General Service 50 to 4,999 kW	803,473	952,274	726,603
Unmetered Scattered Load	22,784	24,387	5,920
Sentinel Lighting	6,559	7,130	12,885
Street Lighting	44,324	48,801	79,319

* per RateMaker sheet F4

Revenue at Existing Rates **

Customer Class	Proceeds from Distribution Charges (A)	Less: Transformer Allowance Recoveries (B)	Less: Low Voltage Charges (C)	Net Distribution Revenue
Residential	2,131,264	0	-87,502	2,043,761
General Service Less Than 50 kW	673,547	0	-39,708	633,839
General Service 50 to 4,999 kW	908,501	-30,354	-74,674	803,473
Unmetered Scattered Load	23,266	0	-482	22,784
Sentinel Lighting	6,802	0	-244	6,559
Street Lighting	46,558	0	-2,234	44,324

** per RateMaker sheet 'NetDistRev'

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 4): Existing Rates

OVERVIEW OF EXISTING RATES

Attachment 1 shows ORPC's existing approved rates, which came into effect May 1, 2009.

The existing rates for Specific Service Charges, Retail Services Charges and Loss Factors were approved by the Board in 2006 as part of the utility's cost of service application.

The class-specific rates for the monthly service charge and distribution volumetric result from the cost of service approval in 2006 and annual adjustments in 2007, 2008 and 2009 under the Board's 2nd Generation Incentive Regulation Mechanism ("2GIRM"). These adjustments included factors for the price cap and the transition towards a 40% deemed equity component in the utility's capital structure,

The monthly service charge levels for metered classes include a $1.00 funding adder for Smart Meters. Distribution Volumetric rates include the following rate adders for Low Voltage service:

Table 1: Low Voltage Rate Adders

	Rate	per
Residential	$0.0011	kWh
General Service Less Than 50 kW	$0.0011	kWh
General Service 50 to 4,999 kW	$0.3526	kW
Unmetered Scattered Load	$0.0011	kWh
Sentinel Lighting	$0.3207	kW
Street Lighting	$0.3260	kW

The distribution volumetric rate for the General Service 50 to 4,999 kW class also includes a component to recover transformer ownership allowances credited to certain customers in that class.

Projected base revenue at existing rates in 2010, excluding the smart meter funding adder and net of the low voltage rate adder and transformer allowance recovery, were presented in Exhibit 3, Tab 2, Schedule 1, Attachment 1. The following table summarizes these revenue projections, showing the proportions attributable to fixed (monthly service) charges and variable (distribution volumetric) charges:

Table 2: 2010 Fixed and Variable Charge Revenues at Existing Rates [1]

2010 Projected Revenue at Existing Rates	**Net Distribution Revenue** *(A)*	**Fixed Charge Revenue** *(B)*	**Fixed %** *(C)*	**Variable %** *(D)*	**Total %** *(E)*
Residential	2,043,761	1,168,737	57.19%	42.81%	57.49%
General Service Less Than 50 kW	633,839	373,933	58.99%	41.01%	17.83%
General Service 50 to 4,999 kW	803,473	467,044	58.13%	41.87%	22.60%
Unmetered Scattered Load	22,784	19,631	86.16%	13.84%	0.64%
Sentinel Lighting	6,559	3,473	52.96%	47.04%	0.18%
Street Lighting	44,324	26,424	59.62%	40.38%	1.25%
TOTAL	**3,554,741**	**2,059,243**	**57.93%**	**42.07%**	**100.00%**

(A) per sheet "Net Distribution Revenue"
(B) per sheet C4
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

[1] source: RateMaker model, sheet ‘FixedVarRevenue’

Ottawa River Power Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0206

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

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

SERVICE CLASSIFICATIONS

Residential
This classification refers to the supply of electrical energy to customers residing in residential dwelling units. Energy is generally supplied as single phase, 3-wire, 60-Hertz, having nominal voltage of 120/240 volts and up to 400 amps. There shall be only one delivery point to a dwelling. The Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service. A Residential building is supplied at one service voltage per land parcel. Depending upon the location of the building the supply voltage will be one of the following:
- 120/240 volts 1 phase 3 wire
- 120/208 volts 1 phase 3 wire
- 120/208 volts 3 phase 4 wire
- 347/600 volts 3 phase 4 wire

General Service Less Than 50 kW
This classification refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single-family dwellings. A General Service building is supplied at one service voltage per land parcel. Depending upon the location of the building the supply voltage will be one of the following:
- 120/240 volts 1 phase 3 wire
- 120/208 volts 1 phase 3 wire
- 120/208 volts 3 phase 4 wire
- 347/600 volts 3 phase 4 wire

General Service 50 to 4, 999 kW
This classification refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load equal to or greater than 50 kW but less than 5,000kW. A General Service building is supplied at one service voltage per land parcel. Depending upon the location of the building the supply voltage will be one of the following:
- 120/240 volts 1 phase 3 wire
- 120/208 volts 3 phase 4 wire
- 347/600 volts 3 phase 4 wire

Depending upon the location of the building, primary supplies to transformers and customer owned Sub-Stations will be one of the following as determined by the Distributor:
- 7,200/12,400 volts 3 phase 4 wire
- 44,000 volts 3 phase 3 wire

Ottawa River Power Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0206

Unmetered Scattered Load
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 level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Sentinel Lighting
This classification refers to privately owned roadway lighting controlled by photo cells. Consumption is based on calculated connected load times the required lighting hours.

Street Lighting
This classification refers to municipal lighting, Ministry of Transportation operation controlled by photo cells. Consumption is as per OEB Street lighting load shape.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.95
Distribution Volumetric Rate	$/kWh	0.0121
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0053
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	23.41
Distribution Volumetric Rate	$/kWh	0.0083
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	271.28
Distribution Volumetric Rate	$/kW	2.0845
Retail Transmission Rate – Network Service Rate	$/kW	1.6741
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8886
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	22.41
Distribution Volumetric Rate	$/kWh	0.0083
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Ottawa River Power Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0206

Sentinel Lighting

Service Charge (per connection)	$	1.34
Distribution Volumetric Rate	$/kW	4.3804
Retail Transmission Rate – Network Service Rate	$/kW	1.2689
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4906
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.83
Distribution Volumetric Rate	$/kW	2.9380
Retail Transmission Rate – Network Service Rate	$/kW	1.2624
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4600
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Account History	$	15.00
Returned Cheque Charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
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
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

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

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

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LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0569
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0464
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Exhibit 8: Rate Design

Tab 2 (of 4): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

The first page of Attachment 1 shows the proposed monthly service charge for each customer class, the resulting splits of base revenue from fixed and variable charges, and the ensuing usage rates. The rate model provided by Elenchus Research Associates ("Elenchus") was designed to present these calculations on the basis of a "Gross Base Revenue Requirement", which includes the recovery of low voltage ("LV") charges and transformer allowances (but not the funding adder for smart meters).

For consistency with the Board's findings in other cost of service applications filed for 2010 rates, an additional calculation was prepared to show the split of base revenue from fixed and variable charges, excluding the recovery of LV charges and transformer allowances. This calculation appears on the second page of Attachment 1.

The fixed charge rates for the Unmetered Scattered Load, Sentinel Lighting and Street Lighting classes were set so as to maintain the existing split of base revenue from fixed and variable charges. The resulting Monthly Service Charge ("MSC") levels fall within the boundaries produced by the 2010 Cost Allocation ("CA") model.

For the General Service 50 – 4,999 kW rate class, maintaining the existing fixed/variable split would result in an MSC below the minimum boundary indicated in the CA model. The minimum boundary from the CA model was therefore used for the MSC rate. Generally, the CA model's 'Avoided Costs' approach yields the lowest fixed charge level. However, in this case the approach based on 'Minimum System costs with PLCC[1] Adjustment' produced a lower fixed charge rate, which is closer to the existing MSC. ORPC proposes to use this lower amount, mitigating the increase in its MSC rate.

For the General Service less than 50kW rate class, maintaining the existing fixed/variable split would result in a fixed rate that exceeded the maximum boundary in

[1] PLCC = 'Peak Load Carrying Capability'

the CA model. The maximum boundary from the CA model was therefore used for the fixed charge rate.

Maintaining the existing fixed/variable split for the Residential class would also result in an MSC higher than the maximum boundary in the CA model. Since the existing MSC also exceeded this boundary, this rate was maintained, in accordance with Board policy that states: *Distributors that are currently above this [ceiling] value are not required to make changes to their current MSC to bring it to or below this level at this time.*[2]

Attachment 2 shows the reconciliation of the revenues from fixed and variable distribution charges (including the LV rate adder) to the "Gross Base Revenue Requirement" (as defined in the Elenchus rate model). The reconciliation for the recovery of LV charges is also shown separately. In both cases, the differences between the calculated revenues (from multiplying rates by applicable volumes) and the allocated revenue amounts are attributable to rounding.

The distribution volumetric rate (excluding the LV rate adder) and the low voltage rate for each customer class appear separately on the proposed rate schedule at Exhibit 8, Tab 4, Schedule 4, Attachment 1.

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[2] Report of the Board: Application of Cost Allocation for Electricity Distributors (EB-2007-0667), November 28, 2007, section 4.2.2

Fixed/Variable Revenue Split

	Existing Rates (1)			Cost Allocation - Minimum Fixed Rate (2)			Cost Allocation - Maximun Fixed Rate (2)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$10.95	54.84%	45.16%	$3.24	13.81%	86.19%	$10.95	46.70%	53.30%
General Service Less Than 50 kW	$22.41	55.52%	44.48%	$11.14	24.06%	75.94%	$22.41	48.38%	51.62%
General Service 50 to 4,999 kW	$270.28	51.41%	48.59%	$432.64	88.91%	11.09%	$652.66	134.13%	-34.13%
Unmetered Scattered Load	$22.41	84.38%	15.62%	$0.09	1.28%	98.72%	$22.41	307.94%	-207.94%
Sentinel Lighting	$1.34	51.06%	48.94%	$0.09	1.84%	98.16%	$7.29	143.91%	-43.91%
Street Lighting	$0.83	56.75%	43.25%	$0.12	4.53%	95.47%	$7.34	287.04%	-187.04%

(1) per sheet C4
(2) Rates per sheet F3; %s based on # customers per sheet C1 and revenue requirement allocated to customer class per sheet F4

	Existing Fixed/Variable Split (3)			Rate Application			Resulting Usage		(4) Existing
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**per**	**Usage Rate**
Residential	$12.86	54.84%	45.16%	$10.95	46.70%	53.30%	$0.0168	kWh	$0.0121
General Service Less Than 50 kW	$25.71	55.52%	44.48%	$22.41	48.38%	51.62%	$0.0111	kWh	$0.0083
General Service 50 to 4,999 kW	$250.14	51.41%	48.59%	$297.48	61.14%	38.86%	$1.5430	kW	$2.0845
Unmetered Scattered Load	$6.14	84.38%	15.62%	$5.82	79.97%	20.03%	$0.0029	kWh	$0.0083
Sentinel Lighting	$2.59	51.06%	48.94%	$2.63	51.95%	48.05%	$8.2971	kW	$4.3804
Street Lighting	$1.45	56.75%	43.25%	$1.49	58.26%	41.74%	$4.9586	kW	$2.9380

(3) %s per Existing Rates, Rate based on Revenue Requirement allocated to Customer Class per sheet F4 and # customers per sheet C1
(4) per sheet C4

FIXED / VARIABLE REVENUE SPLITS

(Excluding Low Voltage rate adder and Transformer Allowance recoveries)

2010 Projected Revenue at Existing Rates	**Net Distribution Revenue** *(A)*	**Fixed Charge Revenue** *(B)*	**Fixed %** *(C)*	**Variable %** *(D)*	**Total %** *(E)*
Residential	2,043,761	1,168,737	57.19%	42.81%	57.49%
General Service Less Than 50 kW	633,839	373,933	58.99%	41.01%	17.83%
General Service 50 to 4,999 kW	803,473	467,044	58.13%	41.87%	22.60%
General Service 50 to 4,999 kW	22,784	19,631	86.16%	13.84%	0.64%
Sentinel Lighting	6,559	3,473	52.96%	47.04%	0.18%
Street Lighting	44,324	26,424	59.62%	40.38%	1.25%
TOTAL	**3,554,741**	**2,059,243**	**57.93%**	**42.07%**	**100.00%**

(A) per sheet "Net Distribution Revenue"
(B) per sheet C4
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

2010 Projected Revenue at Proposed Rates	**Net Distribution Revenue** *(E)*	**Fixed Charge Revenue** *(F)*	**Fixed %** *(G)*	**Variable %** *(H)*	**Total %** *(I)*
Residential	2,412,448	1,168,737	48.45%	51.55%	60.73%
General Service Less Than 50 kW	735,366	373,933	50.85%	49.15%	18.51%
General Service 50 to 4,999 kW	726,603	514,045	70.75%	29.25%	18.29%
Unmetered Scattered Load	5,920	5,098	86.11%	13.89%	0.15%
Sentinel Lighting	12,885	6,817	52.91%	47.09%	0.32%
Street Lighting	79,319	47,436	59.80%	40.20%	2.00%
TOTAL	**3,972,542**	**2,116,067**	**53.27%**	**46.73%**	**100.00%**

(E) Sheet F4; "Total Base Revenue Requirement"
(F) Sheet F6; "Fixed Charge Revenue"
(G) = (F) / (E)
(H) = 1 - (G)
(I) Class Revenue from column (E) divided by Total from column (E)

Reconciliation to Base Revenue Requirement

DISTRIBUTION CHARGES

Customer Class Name	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
	Rate [1]	Volume [2]	Revenue [3]	Rate [1]	Volume [2]	Revenue [3]	Calculated *	Allocated **	Difference
Residential	$10.95	106,734	1,168,737	$0.0168	79,547,654	1,336,401	2,505,138	2,502,874	2,264
General Service Less Than 50 kW	$22.41	16,686	373,933	$0.0111	36,098,055	400,688	774,622	772,833	1,789
General Service 50 to 4,999 kW	$297.48	1,728	514,045	$1.5430	211,781	326,778	840,824	840,815	8
Unmetered Scattered Load	$5.82	876	5,098	$0.0029	437,952	1,270	6,368	6,375	-7
Sentinel Lighting	$2.63	2,592	6,817	$8.2971	760	6,306	13,123	13,123	-0
Street Lighting	$1.49	31,836	47,436	$4.9586	6,853	33,981	81,417	81,417	0
TOTAL			**2,116,067**			**2,105,424**	**4,221,491**	**4,217,436**	**4,055**

[1] From sheet F5, rounded off to decimals displayed
[2] Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

** Sum of 'Revenue' columns*
*** From sheet F4 (Gross Base Revenue Requirement)*

DEFERRAL/VARIANCE ACCOUNT RECOVERY CHARGES (CREDITS)

Customer Class Name		Variable Charge (Credit)			Proceeds from Recovery Charges (Credits)		
		Rate [1]	Volume [2]	Proceeds [3]	Calculated *	Allocated **	Difference
Residential		($0.0115)	79,547,654	-914,798	-914,798	-916,213	1,415
General Service Less Than 50 kW		($0.0039)	36,098,055	-140,782	-140,782	-141,381	599
General Service 50 to 4,999 kW		($0.7139)	211,781	-151,190	-151,190	-151,190	-1
Unmetered Scattered Load		($0.0057)	437,952	-2,496	-2,496	-2,479	-18
Sentinel Lighting		($4.9734)	760	-3,780	-3,780	-3,780	0
Street Lighting		$0.5181	6,853	3,551	3,551	3,551	-0
TOTAL				**-1,209,496**	**-1,209,496**	**-1,211,492**	**1,995**

[1] From sheet C7 ('Proposed Rate Rider'), rounded off to decimals displayed
[2] Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

** = 'Proceds' column*
*** From sheet C7 ('Annual Recovery Amounts')*

DISTRIBUTION RATE ADJUSTMENTS

Attachment 1 shows the proposed adjustments to the fixed and variable rates discussed in the preceding schedule.

For the fixed charge, no adjustments have been specified. The Smart Meter funding adder, which was included in the fixed charge in the 2009 rate order, now appears as a distinct line item on the proposed rate schedule (Exhibit 8, Tab 4, Schedule 4, Attachment 1).

For the variable charge, since the rate model generated a charge level inclusive of a rate adder for low voltage, this adder is removed to produce the base distribution volumetric rates. The low voltage service rates for 2010 now appear as distinct line items on the proposed rate schedule.

Table of Distribution Rate Adjustments

Rate components per sheet Y5

Customer Class Name	PROPOSED FIXED RATES *per Sheet F6*					TOTAL
Residential	$10.95					$10.95
General Service Less Than 50 kW	$22.41					$22.41
General Service 50 to 4,999 kW	$297.48					$297.48
Unmetered Scattered Load	$5.82					$5.82
Sentinel Lighting	$2.63					$2.63
Street Lighting	$1.49					$1.49

Customer Class Name	PROPOSED VARIABLE RATES *per Sheet F6*	Exclude Low Voltage				TOTAL	per
Residential	$0.0168	($0.0011)				$0.0157	kWh
General Service Less Than 50 kW	$0.0111	($0.0010)				$0.0101	kWh
General Service 50 to 4,999 kW	$1.5430	($0.3960)				$1.1470	kW
Unmetered Scattered Load	$0.0029	($0.0010)				$0.0019	kWh
Sentinel Lighting	$8.2971	($0.3125)				$7.9846	kW
Street Lighting	$4.9586	($0.3061)				$4.6525	kW

Exhibit 8: Rate Design

Tab 3 (of 4): Transmission, Low Voltage, Line Losses and WMS

RETAIL TRANSMISSION SERVICE RATES (RTSR)

Board policy states that distributors should file the following material in a cost of service rate application in support of a change to RTSRs:

- *A variance analysis using 2 years of actual data examining what, if any, trend is apparent in the monthly balances in the RTSR deferral accounts*

- *A calculation of the proposed RTSR rates that includes the adjustment of the UTRs effective July 1, 2009 and an adjustment to eliminate ongoing trends in the balances in the RTSR deferral accounts* [1]

Attachment 1 shows the trend for the past two years of transmission revenues and costs, adjusted for consistency with both retail and supply rates that were in effect in December 2009. The trend indicates that these rates were resulting in over-collection of transmission charges of about 8.8% for Network Service and 59.1% for Connection Service. This conclusion is consistent with the accumulation of credit balances in variance accounts 1584-RSVA/NW and 1586-RSVA/CN during this two-year period.[2] ORPC therefore proposes to adjust its RTSRs to offset the over-collection bias in its existing retail rates.

As an embedded distributor, ORPC pays Hydro One Networks Inc. (“HONI”) retail transmission service rates for the supply of transmission services, rather than the Uniform Transmission Rates (“UTRs”) paid by market participants. ORPC also pays transmission charges to Brookfield Energy Management Inc. (“BEMI”), which are treated as Network Service charges. The supply rate changes at the bottom of Attachment 1 reflect the changes in the effective blended rate for the two sources of supply for Network Service, and the changes to HONI’s rate for Connection Service.

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[1] Guideline G-2008-0001: Electricity Distribution Retail Transmission Rates, Revision 1.0 (July 22, 2009), pages 4-5
[2] see Exhibit 9, Tab 1, Schedule 2, Attachment 1

ORPC also proposes to apply an adjustment for changes in the applicable HONI rates which came into effect May 1, 2010.[3] Based on current contract terms, the transmission rate ORPC pays to BEMI is equal to 50% of the combined rate payable to HONI for both Network and Connection services. On this basis, the new blended supply rate for Network Service represents an increase of about 17.8% from the rate in effect in December 2009, while the rate charged by HONI for Connection Service has increased by about 7.5%.

Attachment 2 shows the effect of the two adjustments to ORPC's RTSRs, the first to eliminate the existing variance trend and the second to apply the latest change in transmission supply rates. As a result, ORPC proposes to increase its RTSRs for Network Service by 7.44% and to decrease its RTSRs for Connection Service by 56%. These proposed rate changes were reflected in ORPC's projected power supply expense for 2010, shown in Exhibit 3, Tab 1, Schedule 3, Attachment 1.

[3] Rate Order: HONI 2010 distribution rates (EB-2009-0096), April 29, 2010

Historical Transmission Costs and Revenues

	NETWORK CHARGES					*CONNECTION CHARGES*				
Month (MMM-YYYY)	**Revenues [a]**	**RTSR Δ% [b]**	**Charges [c]**	**Supply Δ% [d]**	**Variance [e]**	**Revenues [a]**	**RTSR Δ% [b]**	**Charges [c]**	**Supply Δ% [d]**	**Variance [e]**
Dec-2009	70,376	0.00%	89,353	0.00%	-21.24%	71,319	0.00%	76,900	0.00%	-7.26%
Nov-2009	64,729	0.00%	69,054	0.00%	-6.26%	74,882	0.00%	57,672	0.00%	29.84%
Oct-2009	65,250	0.00%	69,187	0.00%	-5.69%	75,542	0.00%	53,416	0.00%	41.42%
Sep-2009	67,256	0.00%	74,296	0.00%	-9.48%	77,787	0.00%	53,254	0.00%	46.07%
Aug-2009	61,477	0.00%	79,225	-1.80%	-20.98%	70,936	0.00%	59,622	0.00%	18.98%
Jul-2009	71,589	0.00%	64,846	-1.80%	12.42%	82,880	0.00%	46,706	0.00%	77.45%
Jun-2009	65,074	0.00%	63,524	-1.80%	4.32%	74,361	0.00%	56,434	0.00%	31.77%
May-2009	68,531	0.00%	53,188	7.55%	19.80%	80,323	0.00%	36,358	5.85%	108.71%
Apr-2009	79,470	11.34%	59,437	7.55%	38.42%	94,951	5.00%	44,180	5.85%	113.19%
Mar-2009	83,828	11.34%	69,392	7.55%	25.07%	100,452	5.00%	57,750	5.85%	72.55%
Feb-2009	84,125	11.34%	74,626	7.55%	16.71%	102,171	5.00%	62,328	5.85%	62.61%
Jan-2009	75,062	11.34%	74,219	7.55%	4.70%	93,916	5.00%	69,419	5.85%	34.20%
Dec-2008	36,335	11.34%	101,613	7.55%	-62.98%	72,463	5.00%	93,235	5.85%	-22.90%
Nov-2008	61,939	11.34%	55,860	7.55%	14.80%	68,120	5.00%	52,315	5.85%	29.17%
Oct-2008	63,121	11.34%	65,265	7.55%	0.13%	86,333	5.00%	45,457	5.85%	88.40%
Sep-2008	46,213	11.34%	51,068	7.55%	-6.31%	55,457	5.00%	46,735	5.85%	17.71%
Aug-2008	69,082	11.34%	71,592	7.55%	-0.10%	88,144	5.00%	54,742	5.85%	59.72%
Jul-2008	63,744	11.34%	68,597	7.55%	-3.80%	77,362	5.00%	46,588	5.85%	64.72%
Jun-2008	71,090	11.34%	60,524	7.55%	21.60%	81,139	5.00%	46,964	5.85%	71.38%
May-2008	81,044	11.34%	51,578	-11.43%	97.54%	85,899	5.00%	35,887	-4.79%	163.96%
Apr-2008	95,921	-8.68%	69,790	-11.43%	41.71%	101,903	-0.25%	47,404	-4.79%	125.21%
Mar-2008	92,038	-8.68%	76,331	-11.43%	24.33%	97,674	-0.25%	55,408	-4.79%	84.68%
Feb-2008	81,513	-8.68%	86,387	-11.43%	-2.71%	86,324	-0.25%	64,736	-4.79%	39.70%
Jan-2008	103,463	-8.68%	82,497	-11.43%	29.31%	109,886	-0.25%	68,765	-4.79%	67.42%
ADJUSTED HISTORICAL AVERAGE					**8.80%**					**59.11%**

HISTORICAL RATE CHANGES	**LDC rate % change**		*** Supply % change**	
Month (MMM-YYYY)	**Network**	**Connection**	**Network**	**Connection**
Sep-2009			-1.80%	
Jun-2009			9.52%	5.85%
May-2009	11.34%	5.00%		
Jun-2008			-17.65%	-10.05%
May-2008	-17.99%	-5.00%		

[a] Proceeds from RTS (Retail Transmission Service) charges
[b] % change from prevalent to existing RTS rate
[c] Transmission supply charges
[d] % change from prevalent to existing HONI rates
[e] = (a*(1+b)) / (c*(1+d)) - 1

Calculation of proposed RTSRs

		Existing Rates		2010 Rates *	
Customer Class Name	**Usage Metric**	**Network**	**Connection**	**Network**	**Connection**
Residential	kWh	$0.0045	$0.0053	$0.0048	$0.0023
General Service Less Than 50 kW	kWh	$0.0041	$0.0048	$0.0044	$0.0021
General Service 50 to 4,999 kW	kW	$1.6741	$1.8886	$1.7987	$0.8304
Unmetered Scattered Load	kWh	$0.0041	$0.0048	$0.0044	$0.0021
Sentinel Lighting	kW	$1.2689	$1.4906	$1.3633	$0.6554
Street Lighting	kW	$1.2624	$1.4600	$1.3564	$0.6420
Supply Transmission Rates	kW	$2.2273	$1.9900	$2.6242	$2.1400

** Rate Adjustment Factors:*		
Change in Supply rates, 2010 vs Existing	17.82%	7.54%
Historical Variance (per previous sheet)	-8.80%	-59.11%
Total Adjustment	**7.44%**	**-56.03%**

LOW VOLTAGE CHARGES

Attachment 1 presents the derivation of proposed retail rates for Low Voltage (“LV”) service.

In the first page of the attachment, total LV charges for the 2010 test year are estimated. Actual 2009 volumes were applied to Hydro One Networks Inc.’s approved sub-transmission rates for 2010.[1] An adjustment for a demand increase of 0.3% was also made, based on the change in energy consumption when comparing the 2010 forecast against 2009 actual volumes, to arrive at an estimate of total LV charges for 2010.

The calculation of proposed retail rates for LV service appears on the second page of the attachment. The 2010 estimate of total LV charges was allocated to customer classes, according to each class’ share of projected Transmission-Connection revenue, in accordance with Board policy.[2] The resulting allocated LV charges for each class were divided by the applicable 2010 volumes from the load forecast, as presented in Exhibit 3, Tab 1, Schedule 1, Attachment 1.

Up until 2009, the LV rate for each customer class was embedded as a rate adder within the approved Distribution Volumetric rate. Consistent with the Board’s practice in issuing distributors’ rate orders for 2010, the LV rate now appears as a distinct line item on the proposed schedule of rates (Exhibit 8, Tab 4, Schedule 4, Attachment 1).

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[1] Rate Order, Hydro One Networks Inc. 2010 Distribution Rates (EB-2009-0096), April 29, 2010

[2] Ontario Energy Board, 2006 Electricity Distribution Rate Handbook, May 11, 2005, Section 10.7 (page 96)

Calculation of Low Voltage Rate Adders

Estimated 2010 LV Charges

	Demand (kW)		Common Lines Charge	Shared LVDS	Meter Charge	Monthly Service Charge	TOTAL
	Total	Cobden TS Only					
		2010 rates:	*$0.4420*	*$1.4270*	*$252.71*	*$211.42*	
Jan-2009	36,925	2,696	16,321	3,847	1,264	1,057	**22,489**
Feb-2009	33,153	2,571	14,654	3,669	1,264	1,057	**20,643**
Mar-2009	30,718	2,168	13,577	3,094	1,264	1,057	**18,992**
Apr-2009	23,500	1,803	10,387	2,573	1,264	1,057	**15,281**
May-2009	19,269	1,757	8,517	2,507	1,264	1,057	**13,345**
Jun-2009	28,359	1,530	12,535	2,183	1,264	1,057	**17,039**
Jul-2009	22,842	1,544	10,096	2,203	1,264	1,057	**14,620**
Aug-2009	29,961	1,696	13,243	2,420	1,264	1,057	**17,984**
Sep-2009	26,761	1,718	11,828	2,452	1,264	1,057	**16,601**
Oct-2009	26,842	1,937	11,864	2,764	1,264	1,057	**16,949**
Nov-2009	28,981	2,284	12,810	3,259	1,264	1,057	**18,390**
Dec-2009	34,682	2,804	15,329	4,001	1,264	1,057	**21,651**
Sub-total (2009 demand)	**341,993**	**24,508**	**151,161**	**34,973**	**15,163**	**12,685**	**213,982**
Adjustment for 2010 load increase 0.3%	*1,026*	*74*	*453*	*105*			***558***
TOTAL ESTIMATED 2010 LV CHARGES	**343,019**	**24,582**	**151,614**	**35,078**	**15,163**	**12,685**	**214,540**

Calculation of Low Voltage Rate Adders

Customer Class Name	Test Year Revenues [6] Transmission - Connection	Class Share	Low Voltage Charges [7]	Volume (kWh or kW)	Low Voltage Rate	per
Residential	189,638	42.1%	90,426	79,547,654	$0.0011	kWh
General Service Less Than 50 kW	78,573	17.5%	37,466	36,098,055	$0.0010	kWh
General Service 50 to 4,999 kW	175,863	39.1%	83,858	211,781	$0.3960	kW
Unmetered Scattered Load	953	0.2%	455	437,952	$0.0010	kWh
Sentinel Lighting	498	0.1%	238	760	$0.3125	kW
Street Lighting	4,400	1.0%	2,098	6,853	$0.3061	kW
TOTAL	**449,924**	**100.0%**	**214,540**			
		OK				

[6] charge type per sheet Y4; amounts per sheet C2;

[7] Total per sheet C2; allocated to customer classes based on Class Share

LOSS ADJUSTMENT FACTORS

Attachment 1 shows the calculation of ORPC's proposed Total Loss Factor, based on the historical average of the last five years.

ORPC is an embedded distributor with Hydro One Networks Inc. ("HONI") as its host distributor. The Supply Facility Loss Factor ("SFLF") from HONI varies within ORPC's service territory: Pembroke is subject to a SFLF of 1.006, while Killaloe, Beachburg and Almonte are subject to a SFLF of 1.034. ORPC also receives power from local generators without upstream losses. The second page of Attachment 1 shows the calculation of ORPC's overall SFLF for each of the last five years, based on the upstream losses from these supply points.

ORPC proposes a Total Loss Factor ("TLF") 1.0390, using the historical average of the last five years as presented on the first page of Attachment 1. The proposed TLF represents a significant decrease from ORPC's currently approved TLF of 1.0569.

Line Loss Drivers

In 2007 ORPC undertook a project to model the distribution system. One of the benefits of the modeling is the ability to understand calculated or theoretical loss factors. Based on modeled results and an understanding of ORPC's distribution system, the following factors were identified as key drivers of reported distribution line losses:

- Changes year over year are influenced in part by the limitation of year-end sales estimates for unbilled revenue done within the Customer Information System. The deployment of Smart Meters provides an opportunity for more accurate reporting.

- Line losses (I^2R) would be expected to be lower in a large part of the service area that was historically built for electric heat but is now mostly gas heated. Larger conductors would be expected to reduce losses.

- Total loss factors are favourably impacted by the significant amount of local embedded generation in Pembroke and Almonte. Embedded generation connected at the distribution level avoids sub-transmission line and station transformer losses

- Modelling indicates that the largest percentage of line losses are transformer no load and series losses. Over-sizing of transformers for electric heat will usually reduce the series losses, subject to other variables relating to the quality of core steel and core construction. Unfortunately the model depends on the use of typical impedances for transformers, yielding results that are higher than loss levels actually experienced. Further refinement of the model in this area will increase the validity of its results.

ORPC plans to continue using and refining this model, reflecting changes arising from the extent of local generation and increased data precision from smart meters, before determining any new measures that would further mitigate line losses in its distribution system.

LINE LOSS FACTORS

		2005	2006	2007	2008	2009	AVERAGE
	Losses in Distributor's System						
A_1	"Wholesale" kWh delivered to distributor (higher value)						
A_2	"Wholesale" kWh delivered to distributor (lower value)	206,431,279	197,679,081	202,576,465	200,871,036	199,359,940	
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customers						
C	Net "Wholesale" kWh delivered to distributor: (A_2)-(B)	206,431,279	197,679,081	202,576,465	200,871,036	199,359,940	
D	"Retail" kWh delivered to distributor	199,131,058	193,831,419	197,591,897	196,409,498	191,997,485	
E	Portion of "Retail" kWh delivered to distributor for Large Use Customers						
F	Net "Retail" kWh delivered to distributor: (D)-(E)	199,131,058	193,831,419	197,591,897	196,409,498	191,997,485	
G	Loss Factor in distributor's system: (C)/(F)	1.0367	1.0199	1.0252	1.0227	1.0383	1.0286
	Losses upstream of Distributor's System						
H	Supply Facility Loss Factor	1.0099	1.0092	1.0100	1.0093	1.0123	1.0101
	Total Losses						
I	**Total Loss Factor: (G)x(H)**	**1.0469**	**1.0292**	**1.0355**	**1.0323**	**1.0511**	**1.0390**

J	Primary Metering Adjustment	0.99
	Total Loss Factor for Primary Metered Customer: (I)x(J)	1.0286

SUPPLY FACILITY LOSS FACTORS

	2005		2006		2007	
	Without Losses	**With Losses**	**Without Losses**	**With Losses**	**Without Losses**	**With Losses**
Hydro One	159,667,539	161,715,832	123,317,173	125,136,621	152,570,455	154,598,242
Brookfield	38,241,504	38,241,504	60,633,156	60,633,156	39,895,000	39,895,000
Mississippi River Power Generation	6,707,865	6,707,865	11,631,642	11,631,642	8,698,447	8,698,447
Enerdu	1,814,371	1,814,371	2,097,110	2,097,110	1,412,563	1,412,563
Total	**206,431,279**	**208,479,572**	**197,679,081**	**199,498,529**	**202,576,465**	**204,604,252**
Loss Factor		*1.0099*		*1.0092*		*1.0100*

	2008		2009	
	Without Losses	**With Losses**	**Without Losses**	**With Losses**
Hydro One	135,419,364	137,292,126	147,390,887	149,836,759
Brookfield	54,760,760	54,760,760	50,210,700	50,210,700
Mississippi River Power Generation	9,191,039	9,191,039	0	0
Enerdu	1,499,873	1,499,873	1,740,770	1,740,770
Total	**200,871,036**	**202,743,798**	**199,342,357**	**201,788,229**
Loss Factor		*1.0093*		*1.0123*

WHOLESALE MARKET SERVICE (WMS) RATE

Attachment 1 presents the trend in WMS charges for the past two years and the ensuing proposed adjustment to the rate charged to ORPC's customers.

As the Attachment shows, ORPC has been over-collecting WMS charges from its customers, resulting in the accumulation of a significant credit balance in its 1580-RSVA/WMS variance account.[1] The over-collection stems from the fact that ORPC pays a lower WMS rate for power delivered from the Brookfield generation station, in accordance with Board-approved contract terms.[2]

In the absence of any established Board guideline for adjustments to the WMS rate, ORPC proposes to follow an approach similar to the one prescribed by the Board for Retail Transmission Service charges, whereby a variance analysis using two years of actual data is used to determine the apparent trend in the related variance account balance,[3] and thus derive an adjustment factor to eliminate the ongoing accumulation of significant balances in the 1580-RSVA/WMS variance account..

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[1] see Exhibit 9, Tab 1, Schedule 2, Attachment 1

[2] see EB-2008-0289

[3] Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, Revision 1.0 (July 22, 2009), page 4

Wholesale Market Service Charges

Month (MMM-YYYY)	Revenues [a]	Rate Δ% [b]	Charges [c]	Rate Δ% [d]	Variance [e]
Dec-2009	96,208	0.00%	92,917	0.00%	3.54%
Nov-2009	96,281	0.00%	75,286	0.00%	27.89%
Oct-2009	95,805	0.00%	83,748	0.00%	14.40%
Sep-2009	103,926	0.00%	83,140	0.00%	25.00%
Aug-2009	90,639	0.00%	79,581	0.00%	13.90%
Jul-2009	105,556	0.00%	59,049	0.00%	78.76%
Jun-2009	94,974	0.00%	59,237	0.00%	60.33%
May-2009	102,032	0.00%	53,317	0.00%	91.37%
Apr-2009	128,280	0.00%	66,235	0.00%	93.67%
Mar-2009	130,640	0.00%	76,431	0.00%	70.93%
Feb-2009	134,677	0.00%	100,998	0.00%	33.35%
Jan-2009	120,132	0.00%	112,885	0.00%	6.42%
Dec-2008	99,059	0.00%	80,818	0.00%	22.57%
Nov-2008	86,946	0.00%	80,206	0.00%	8.40%
Oct-2008	113,703	0.00%	60,655	0.00%	87.46%
Sep-2008	74,035	0.00%	57,748	0.00%	28.20%
Aug-2008	105,857	0.00%	60,620	0.00%	74.62%
Jul-2008	97,310	0.00%	50,429	0.00%	92.97%
Jun-2008	99,189	0.00%	49,921	0.00%	98.69%
May-2008	105,981	0.00%	44,077	0.00%	140.45%
Apr-2008	127,398	0.00%	49,593	0.00%	156.89%
Mar-2008	127,613	0.00%	83,064	0.00%	53.63%
Feb-2008	112,012	0.00%	84,800	0.00%	32.09%
Jan-2008	133,748	0.00%	84,392	0.00%	58.48%
ADJUSTED HISTORICAL AVERAGE					**57.25%**

[a] Proceeds from retail charges
[b] % change from prevalent to existing retail rate (none)
[c] WMS supply charges
[d] % change from prevalent to existing supply rate (none)
[e] = (a*(1+b)) / (c*(1+d)) - 1

Existing WMS Rate		$0.0052	*from sheet C2*
Over-collection adjustment	*-57.25%*	($0.0030)	*per above*
Proposed WMS Rate		**$0.0022**	

Exhibit 8: Rate Design

Tab 4 (of 4): Rate Schedules and Bill Impacts

BASE REVENUE CALCULATIONS AND RECONCILIATIONS

The calculation of base revenue by customer class under current rates was presented in Exhibit 3, Tab 2, Schedule 1, Attachment 1.

Attachment 1 to this schedule shows the projected revenue from distribution charges based on proposed rates. The fixed rate does not include the funding adder for smart meters. However, the variable rate does include a low voltage (“LV”) rate adder and the recovery of transformer allowances. Note that all these components were excluded in deriving the split of distribution revenues from fixed and variable rates, as explained in Exhibit 8, Tab 2, Schedule 1.

In the proposed schedule of rates (Exhibit 4, Tab 4, Schedule 4, Attachment 1), the LV rate adder appears as a distinct line item and thus was excluded from the distribution volumetric rate in each customer class.

Attachment 1 shows that the sum of revenues allocated to each class corresponds to the total revenue required for the base revenue requirement, the recovery of LV charges and the recovery of transformer allowances. The Attachment also shows that the revenues calculated for each customer class correspond to the allocated amount, with any differences due entirely to rounding.

Reconciliation of Revenue from Distribution Charges

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$10.95	106,734	1,168,737	$0.0168	79,547,654	1,336,401	2,505,138	2,502,874	2,264
General Service Less Than 50 kW	$22.41	16,686	373,933	$0.0111	36,098,055	400,688	774,622	772,833	1,789
General Service 50 to 4,999 kW	$297.48	1,728	514,045	$1.5430	211,781	326,778	840,824	840,815	8
Unmetered Scattered Load	$5.82	876	5,098	$0.0029	437,952	1,270	6,368	6,375	-7
Sentinel Lighting	$2.63	2,592	6,817	$8.2971	760	6,306	13,123	13,123	-0
Street Lighting	$1.49	31,836	47,436	$4.9586	6,853	33,981	81,417	81,417	0
TOTAL			**2,116,067**			**2,105,424**	**4,221,491**	**4,217,436**	**4,055**

[1] From sheet F5, rounded off to decimals displayed
[2] Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

** Sum of 'Revenue' columns*
*** From sheet F4 (Gross Base Revenue Requirement)*

Base Revenue Requirement	3,972,542
Low Voltage Charges	214,540
Transformer Allowance Recoveries	30,354
TOTAL	**4,217,436**

TOTAL SERVICE REVENUE REQUIREMENT

The following table summarizes the utility's projected 2010 service revenues under both existing and proposed rates.

Table 1: Total Service Revenues

	Existing Rates [1]	Proposed Rates [2]
Gross Base Revenue	$ 3,789,939	$ 4,217,436
- Low Voltage Charges	(204,844)	(214,500)
- Transformer Allowances	(30,354)	(30,354)
Net Base Revenue	$ 3,554,741	$ 3,972,542
+ Revenue Offsets [3]	377,968	377,968
Total Service Revenues	**$ 3,932,709**	**$ 4,350,510**

[1] for Base Revenues, see: Exhibit 3, Tab 2, Schedule 1, Attachment 1
[2] for Base Revenues, see: Exhibit 8, Tab 4, Schedule 1, Attachment 1
[3] per Exhibit 3, Tab 3, Schedule 4, Attachment 1:

Other Revenue	$383,968
- 50% offset for gain on disposition	(6,000)
Revenue Offset amount	**$377,968**

PROPOSED CHANGES TO CONDITIONS OF SERVCE

ORPC does not plan any changes to its conditions of service, other than changes that may be required to ensure continued compliance with the Distribution System Code or other regulatory requirements.

RATE CHANGES AND BILL IMPACTS

Attachment 1 presents the proposed rates to appear on the draft rate order. For each customer class, the following rates appear:

Table 1: Customer Class Rates

Service Charge	Includes the fixed monthly service charge in base revenue (Exhibit 8, Tab 2, Schedule 2, Attachment 1) and the Smart Meter Funding Adder (Exhibit 9, Tab 3, Schedule 2, Attachment 1)
Distribution Volumetric Rate	The variable charge rate (Exhibit 8, Tab 2, Schedule 2, Attachment 1), excluding the low voltage charge (see below)
Low Voltage Service Rate	see Exhibit 8, Tab 3, Schedule 2, Attachment 1
Deferral Account Rate Rider	see Exhibit 9, Tab 2, Schedule 2, Attachment 2
Global Adjustment Rate Rider	see Exhibit 9, Tab 2, Schedule 2, Attachment 1
Transmission- Connection	see Exhibit 8, Tab 3, Schedule 1, Attachment 2
Transmission- Network	see Exhibit 8, Tab 3, Schedule 1, Attachment 2
Wholesale Market Service	see Exhibit 8, Tab 3, Schedule 4, Attachment 1
Rural Rate Protection Charge	no change proposed
Standard Supply Service	no change proposed

In addition to the existing customer classes, a new class has been added for microFIT Generator Service, in accordance with the Board's related rate order.[1]

ORPC proposes to retain the same Specific Service Charges and Allowances, with no rate changes.

The Total Loss Factors are presented in Exhibit 8, Tab 3, Schedule 3, Attachment 1.

Attachment 2 presents detailed sample bill impacts, comparing monthly customer bills under the existing (2009) rates to the proposed (2010) rates. The first page summarizes the bill impacts, while the following pages show the line item details for each sample bill.

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[1] Rate Order: Distribution Rate for Embedded Generators having a nameplate capacity of 10 kW or less (EB-2009-0326), March 17, 2010

The same charge rates shown in Table 1 also appear in each sample bill, with the following provisos:

- The 'Distribution' line item in the sample bill impacts includes the Low Voltage rate.
- The Global Adjustment Rate Rider, which would apply solely to non-RPP, non-MUSH customers,[2] is not reflected.
- An uplift factor for line losses applies to commodity and certain delivery charges, where the billing determinant is consumption (kWh's).

The following additional line items appear in the sample bills:

- A commodity charge, which is based on the approved rates for RPP customers,[3] or using the weighted average forecast electricity price for other customers.[4] To isolate the impact of delivery rate changes, the same commodity charge levels are used in comparing sample bills under existing and proposed rates.
- The existing Debt Retirement Charge

The sample bill impacts do not include the recovery of the special-purpose charge assessment for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs, as set out in the Board's letter of April 9, 2010 to electricity distributors.

Total bill impacts vary by customer class, ranging from a decrease of 37.8% for Unmetered Scattered Load, to an increase of 8.6% for Street Lighting. While base distribution rates would generally increase to address the revenue deficiency, these

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[2] RPP: Regulated Price Plan; MUSH: Municipalities, Universities, Schools & Hospitals

[3] Regulated Price Plan Report – Price Report, April 15, 2010, page iii, values $RPCMT_1$ and $RPCMT_2$

[4] see Table 2 in Exhibit 3, Tab 1, Schedule 3

increases would be offset by credit rate riders to dispose of the significant balances owed to ratepayers that have accumulated in certain variance accounts. Decreases in rates for retail transmission service and wholesale market service, along with a decrease in the line loss factor, also contribute to offset the increase in base distribution rates.

Under these proposed rates, no customer class would face a total bill increase in excess of 10%. In these circumstances, ORPC does not propose any further measures to mitigate customer bill impacts.

Proposed Rate Schedule

		Effective May 1/10
Residential		
Service Charge	$	12.49
Distribution Volumetric Rate	$/kWh	0.0157
Low Voltage Service Rate	$/kWh	0.0011
Deferral Account Rate Rider - effective until April 30, 2014	$/kWh	(0.0115)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0023
Wholesale Market Service Rate	$/kWh	0.0022
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	23.95
Distribution Volumetric Rate	$/kWh	0.0101
Low Voltage Service Rate	$/kWh	0.0010
Deferral Account Rate Rider - effective until April 30, 2014	$/kWh	(0.0039)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0105
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	0.0022
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 50 to 4,999 kW		
Service Charge	$	299.02
Distribution Volumetric Rate	$/kW	1.1470
Low Voltage Service Rate	$/kW	0.3960
Deferral Account Rate Rider - effective until April 30, 2014	$/kW	(0.7139)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kW	1.7987
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8304
Wholesale Market Service Rate	$/kWh	0.0022
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Rate Schedule

		Effective May 1/10
Unmetered Scattered Load		
Service Charge	$	5.82
Distribution Volumetric Rate	$/kWh	0.0019
Low Voltage Service Rate	$/kWh	0.0010
Deferral Account Rate Rider - effective until April 30, 2014	$/kWh	(0.0057)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0105
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	0.0022
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Sentinel Lighting		
Service Charge (per connection)	$	2.63
Distribution Volumetric Rate	$/kW	7.9846
Low Voltage Service Rate	$/kW	0.3125
Deferral Account Rate Rider - effective until April 30, 2014	$/kW	(4.9734)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kW	1.3633
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6554
Wholesale Market Service Rate	$/kWh	0.0022
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Street Lighting		
Service Charge (per connection)	$	1.49
Distribution Volumetric Rate	$/kW	4.6525
Low Voltage Service Rate	$/kW	0.3061
Deferral Account Rate Rider - effective until April 30, 2014	$/kW	0.5181
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kW	1.3564
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6420
Wholesale Market Service Rate	$/kWh	0.0022
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
microFIT Generator Service (effective September 21, 2009)		
Service Charge	$	5.25

Proposed Rate Schedule

		Effective May 1/10
Specific Service Charges		
Arrears Certificate	$	15.00
Account history	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Late Payment - per month	%	1.50
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	-0.30
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
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		
Secondary Metered Customer < 5,000 kW		1.0390
Primary Metered Customer < 5,000 kW		1.0286

Detailed Sample Bill Impacts

Customer Class Name	Volume		RPP	Distribution Charges *		Delivery Sub-total		Total Bill	
	kWh	kW	Rate Class	$ change	% change	$ change	% change	$ change	% change
Residential	800		Summer	$4.30	19.9%	($7.28)	(24.3%)	($10.83)	(12.0%)
	1,000		Winter	$5.24	21.8%	($9.24)	(26.9%)	($13.67)	(12.7%)
General Service Less Than 50 kW	2,000		Non-res.	$6.14	15.3%	($6.98)	(11.9%)	($15.84)	(7.3%)
General Service 50 to 4,999 kW	45,900	120	Non-res.	($37.24)	(7.1%)	($234.94)	(24.8%)	($438.39)	(9.3%)
Unmetered Scattered Load	500		Non-res.	($19.29)	(72.6%)	($23.47)	(75.1%)	($25.61)	(37.8%)
Sentinel Lighting	102	0.29	n/a	$2.44	92.9%	$0.76	22.1%	$0.31	2.6%
Street Lighting	76	0.22	n/a	$1.09	74.9%	$1.05	51.7%	$0.71	8.6%

** Includes Low Voltage charges*

Detailed Sample Bill Impacts

RPP rates per shee

Residential **RPP: Winter**

1,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.95			$12.49	$0.54	4.5%
†	Distribution	kWh	1,000	$0.0121	$12.10	1,000	$0.0168	$16.80	$4.70	38.8%
	Sub-Total (Distribution)				**$24.05**			**$29.29**	**$5.24**	**21.8%**
†	Deferral/Variance	kWh	1,000			1,000	($0.0115)	($11.50)	($11.50)	
	Electricity (Commodity)	kWh	1,057	RPP-Winter	$61.81	1,039	RPP-Winter	$60.61	($1.20)	(1.9%)
†	Transmission - Network	kWh	1,057	$0.0045	$4.76	1,039	$0.0048	$4.99	$0.23	4.8%
†	Transmission - Connection	kWh	1,057	$0.0053	$5.60	1,039	$0.0023	$2.39	($3.21)	(57.3%)
	Wholesale Market Service	kWh	1,057	$0.0052	$5.50	1,039	$0.0022	$2.29	($3.21)	(58.4%)
	Rural Rate Protection	kWh	1,057	$0.0013	$1.37	1,039	$0.0013	$1.35	($0.02)	(1.5%)
	Debt Retirement Charge	kWh	1,000	$0.0049	$4.90	1,000	$0.0049	$4.90		
	TOTAL BILL				**$107.99**			**$94.32**	**($13.67)**	**(12.7%)**
†	*Delivery Only*				*$34.41*			*$25.17*	*($9.24)*	*(26.9%)*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Summer**

800 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.95			$12.49	$0.54	4.5%
†	Distribution	kWh	800	$0.0121	$9.68	800	$0.0168	$13.44	$3.76	38.8%
	Sub-Total (Distribution)				**$21.63**			**$25.93**	**$4.30**	**19.9%**
†	Deferral/Variance	kWh	800			800	($0.0115)	($9.20)	($9.20)	
	Electricity (Commodity)	kWh	846	RPP-Summer	$51.25	831	RPP-Summer	$50.29	($0.96)	(1.9%)
†	Transmission - Network	kWh	846	$0.0045	$3.80	831	$0.0048	$3.99	$0.19	5.0%
†	Transmission - Connection	kWh	846	$0.0053	$4.48	831	$0.0023	$1.91	($2.57)	(57.4%)
	Wholesale Market Service	kWh	846	$0.0052	$4.40	831	$0.0022	$1.83	($2.57)	(58.4%)
	Rural Rate Protection	kWh	846	$0.0013	$1.10	831	$0.0013	$1.08	($0.02)	(1.8%)
	Debt Retirement Charge	kWh	800	$0.0049	$3.92	800	$0.0049	$3.92		
	TOTAL BILL				**$90.58**			**$79.75**	**($10.83)**	**(12.0%)**
†	*Delivery Only*				*$29.91*			*$22.63*	*($7.28)*	*(24.3%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW **RPP: Non-res.**

2,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$23.41			$23.95	$0.54	2.3%
†	Distribution	kWh	2,000	$0.0083	$16.60	2,000	$0.0111	$22.20	$5.60	33.7%
	Sub-Total (Distribution)				**$40.01**			**$46.15**	**$6.14**	**15.3%**
†	Deferral/Variance	kWh	2,000			2,000	($0.0039)	($7.80)	($7.80)	
	Electricity (Commodity)	kWh	2,114	RPP-Non-res.	$134.87	2,078	RPP-Non-res.	$132.48	($2.39)	(1.8%)
†	Transmission - Network	kWh	2,114	$0.0041	$8.67	2,078	$0.0044	$9.14	$0.47	5.4%
†	Transmission - Connection	kWh	2,114	$0.0048	$10.15	2,078	$0.0021	$4.36	($5.79)	(57.0%)
	Wholesale Market Service	kWh	2,114	$0.0052	$10.99	2,078	$0.0022	$4.57	($6.42)	(58.4%)
	Rural Rate Protection	kWh	2,114	$0.0013	$2.75	2,078	$0.0013	$2.70	($0.05)	(1.8%)
	Debt Retirement Charge	kWh	2,000	$0.0049	$9.80	2,000	$0.0049	$9.80		
	TOTAL BILL				**$217.24**			**$201.40**	**($15.84)**	**(7.3%)**
†	*Delivery Only*				*$58.83*			*$51.85*	*($6.98)*	*(11.9%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 4,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
45,900 kWh's										
120 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
† Monthly Service Charge				$271.28			$299.02	$27.74	10.2%
† Distribution	kW	120	$2.0845	$250.14	120	$1.5430	$185.16	($64.98)	(26.0%)
Sub-Total (Distribution)				**$521.42**			**$484.18**	**($37.24)**	**(7.1%)**
† Deferral/Variance	kW	120			120	($0.7139)	($85.67)	($85.67)	
Electricity (Commodity)	kWh	48,512	RPP-Non-res.	$3,243.53	47,690	RPP-Non-res.	$3,188.49	($55.04)	(1.7%)
† Transmission - Network	kW	120	$1.6741	$200.89	120	$1.7987	$215.84	$14.95	7.4%
† Transmission - Connection	kW	120	$1.8886	$226.63	120	$0.8304	$99.65	($126.98)	(56.0%)
Wholesale Market Service	kWh	48,512	$0.0052	$252.26	47,690	$0.0022	$104.92	($147.34)	(58.4%)
Rural Rate Protection	kWh	48,512	$0.0013	$63.07	47,690	$0.0013	$62.00	($1.07)	(1.7%)
Debt Retirement Charge	kWh	45,900	$0.0049	$224.91	45,900	$0.0049	$224.91		
TOTAL BILL				**$4,732.71**			**$4,294.32**	**($438.39)**	**(9.3%)**
† *Delivery Only*				*$948.94*			*$714.00*	*($234.94)*	*(24.8%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Non-res.**

500 kWh's

		Metric	2009 BILL			2010 BILL			CHANGE IMPACT	
			Volume	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$22.41			$5.82	($16.59)	(74.0%)
†	Distribution	kWh	500	$0.0083	$4.15	500	$0.0029	$1.45	($2.70)	(65.1%)
	Sub-Total (Distribution)				**$26.56**			**$7.27**	**($19.29)**	**(72.6%)**
†	Deferral/Variance	kWh	500			500	($0.0057)	($2.85)	($2.85)	
	Electricity (Commodity)	kWh	528	RPP-Non-res.	$30.65	519	RPP-Non-res.	$30.13	($0.52)	(1.7%)
†	Transmission - Network	kWh	528	$0.0041	$2.17	519	$0.0044	$2.29	$0.12	5.5%
†	Transmission - Connection	kWh	528	$0.0048	$2.54	519	$0.0021	$1.09	($1.45)	(57.1%)
	Wholesale Market Service	kWh	528	$0.0052	$2.75	519	$0.0022	$1.14	($1.61)	(58.5%)
	Rural Rate Protection	kWh	528	$0.0013	$0.69	519	$0.0013	$0.68	($0.01)	(1.4%)
	Debt Retirement Charge	kWh	500	$0.0049	$2.45	500	$0.0049	$2.45		
	TOTAL BILL				**$67.81**			**$42.20**	**($25.61)**	**(37.8%)**
†	*Delivery Only*				*$31.27*			*$7.80*	*($23.47)*	*(75.1%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

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Sentinel Lighting **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
102 kWh's										
0.29 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$1.34			$2.63	$1.29	96.3%
†	Distribution	kW	0.29	$4.3804	$1.28	0.29	$8.2971	$2.43	$1.15	89.4%
	Sub-Total (Distribution)				**$2.62**			**$5.06**	**$2.44**	**92.9%**
†	Deferral/Variance	kW	0.29			0.29	($4.9734)	($1.46)	($1.46)	
	Electricity (Commodity)	kWh	108	$0.0674	$7.29	106	$0.0674	$7.17	($0.12)	(1.6%)
†	Transmission - Network	kW	0.29	$1.2689	$0.37	0.29	$1.3633	$0.40	$0.03	8.1%
†	Transmission - Connection	kW	0.29	$1.4906	$0.44	0.29	$0.6554	$0.19	($0.25)	(56.8%)
	Wholesale Market Service	kWh	108	$0.0052	$0.56	106	$0.0022	$0.23	($0.33)	(58.9%)
	Rural Rate Protection	kWh	108	$0.0013	$0.14	106	$0.0013	$0.14		
	Debt Retirement Charge	kWh	102	$0.0049	$0.50	102	$0.0049	$0.50		
	TOTAL BILL				**$11.92**			**$12.23**	**$0.31**	**2.6%**
†	*Delivery Only*				*$3.43*			*$4.19*	*$0.76*	*22.1%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
76 kWh's										
0.22 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge				$0.83			$1.49	$0.66	79.5%
†	Distribution	kW	0.22	$2.9380	$0.63	0.22	$4.9586	$1.07	$0.43	68.8%
	Sub-Total (Distribution)				**$1.46**			**$2.56**	**$1.09**	**74.9%**
†	Deferral/Variance	kW	0.22			0.22	$0.5181	$0.11	$0.11	
	Electricity (Commodity)	kWh	80	$0.0674	$5.40	79	$0.0674	$5.31	($0.09)	(1.7%)
†	Transmission - Network	kW	0.22	$1.2624	$0.27	0.22	$1.3564	$0.29	$0.02	7.4%
†	Transmission - Connection	kW	0.22	$1.4600	$0.31	0.22	$0.6420	$0.14	($0.17)	(54.8%)
	Wholesale Market Service	kWh	80	$0.0052	$0.42	79	$0.0022	$0.17	($0.25)	(59.5%)
	Rural Rate Protection	kWh	80	$0.0013	$0.10	79	$0.0013	$0.10		
	Debt Retirement Charge	kWh	76	$0.0049	$0.37	76	$0.0049	$0.37		
	TOTAL BILL				**$8.33**			**$9.05**	**$0.71**	**8.6%**
†	*Delivery Only*				*$2.04*			*$3.10*	*$1.05*	*51.7%*

<u>Exhibit 9</u>:

DEFERRAL AND VARIANCE ACCOUNTS

Exhibit 9: Deferral And Variance Accounts

Tab 1 (of 3): Status of Deferral and Variance Accounts

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

As at December 31, 2009, ORPC has balances in the following Board-approved deferral and variance accounts categorized by the Board as "Group 1", which do not require a prudence review:[1]

Table 1: Group 1 Deferral and Variance Accounts

1550-LV Variance Account	The difference between amounts charged to the utility for low voltage services, and amounts charged to utility customers through its approved low voltage rates
1580-RSVA/WMS	The difference between amounts charged to the utility for wholesale market service, and amounts charged to utility customers through its approved wholesale market service rate
1584-RSVA/NW	The difference between amounts charged to the utility for transmission network services, and amounts charged to utility customers through its approved transmission network service rate
1586-RSVA/CN	The difference between amounts charged to the utility for transmission connection services, and amounts charged to utility customers through its approved transmission connection service rate
1588-RSVA/POWER	The difference between amounts charged to the utility for energy, and amounts billed to customers for energy, excluding the Global Adjustment sub-account described below.
1588-RSVA/POWER sub-account Global Adjustment	The difference between amounts charged to the utility for the global adjustment in respect of non-RPP customers, and the global adjustment amounts charged to the utility's non-RPP customers.
1590-Recovery of Regulatory Asset Balances	The difference between the regulatory balances approved by the Board for disposition, and the amounts received from or credited to utility customers through its approved regulatory asset rate rider

[1] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), July 31, 2009, pages 6-7

As at December 31, 2009, ORPC has balances in the following Board-approved deferral and variance accounts categorized by the Board as "Group 2", which are subject to a prudence review:[2]

Table 2: Group 2 Deferral and Variance Accounts

1508-Other Regulatory Assets	Amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board.
1555-Smart Meters Capital Variance Account	The difference between capital costs incurred for the deployment of smart meters, and amounts charged to utility customers through its approved smart meter funding adder
1556-Smart Meters OM&A Variance Account	Incremental costs for operations, maintenance, administration and amortization directly associated with smart meters
1562-Deferred Payments in Lieu of Taxes	The amount resulting from the Board-approved PILs methodology for determining the 2001 Deferral Account Allowance and the PILs proxy amount determined for 2002 and subsequent years
1592-PILS & Tax Variance for 2006 and Subsequent years	The tax impact of any differences after May 1, 2006 arising from changes in the 2006 opening balances, and any regulatory or legislative chabges to the tax rates and rules assumed in the 2006 OEB Tax Model.

ORPC's usage of all deferral and variance accounts is consistent with applicable Board definitions and requirements,[3] including the application of carrying charges using approved rates where authorized.

As part of this application, ORPC proposes to establish a new deferral account to track Provincial Sales Tax ("PST") paid during the first six months of 2010. ORPC's projections for the 2010 test year do not include amounts for PST,[4] which is being eliminated effective July 1, 2010. This deferral account would ultimately allow ORPC to recover PST amounts paid in 2010, since it would not be recovering these amounts through its revenue requirement.

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[2] *ibid.*
[3] Ontario Energy Board, Accounting Procedures Handbook for Electric Distribution Utilities, Revised July 31, 2007, Article 220, pages 14-38
[4] see Exhibit 1, Tab 4, Schedule 5, Attachment 2

DEFERRAL AND VARIANCE ACCOUNT BALANCES

Attachment 1 presents the continuity statements for ORPC's deferral and variance accounts, beginning with the 2005 actual opening balances as these reflect the amounts which were previously reviewed by the Board.

ORPC's rate model does not explicitly support sub-accounts; therefore the Global Adjustment sub-account of the 1588-RSVA/Power account is presented in the Attachment as '1572-GLOBAL ADJUSTMENT'. The line item '1588-RSVAPOWER' excludes the balance of the Global Adjustment sub-account.

The year-ending balances are consistent with the historical results reported in Exhibit 1, Tab 4, Schedule 3, Attachment 1, with the following exception for the 2006 ending balances only:

Table 1: Differences in reported 2006 year-end balances

	E1.T4.S3.A1	E9.T1.S2.A1	Difference
1508-Other Regulatory Assets	186,115	141,795	(44,320)
1525-Miscellaneous Deferred Debits	18,683	63,003	44,320

The above differences arise from a posting error which was corrected in 2007. Since the aggregate difference was nil and the same carrying charge rate applies to both affected accounts, the error has no impact on the amounts proposed for disposition.

ORPC has applied carrying charges to its balances as permitted by the APH,[1] using the prescribed interest rates published quarterly on the Board's website.[2] Prior to April 2006, the deemed debt rate of 7.25% was used to calculate carrying charges for RSVA accounts.

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[1] Ontario Energy Board, Accounting Procedures Handbook for Electric Distribution Utilities, Revised July 31, 2007, Article 220, pages 14-38

[2] see: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

Account 1508-Other Regulatory Assets is the only Group 2 deferral/variance account [3] with a balance for proposed disposition.[4] The balance in this account relates to:

- Accrued pension benefits from January 2005 to April 2006 ($83K)
- OEB assessment charges ($23K)
- Charges for capital costs from Hydro One Networks Inc. ($22K)

These charges were prudently incurred and consistent with the requirements of the APH.

[3] see Table 2 in Exhibit 9, Tab 1, Schedule 1
[4] see Exhibit 9, Tab 2, Schedule 1

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	1-Jan-2005 to 31-Dec-2005					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets		126,438	126,438		6,366	6,366
1525-Miscellaneous Deferred Debits	56,057		56,057		4,064	4,064
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	-196,975	71,556	-125,419		-9,093	-9,093
1565-Conservation and Demand Management Expenditures and Recoveries		-218,240	-218,240			
1566-CDM Contra Account		218,240	218,240			
1570-Qualifying Transition Costs	380,699	-41,463	339,236		21,447	21,447
1571-Pre-market Opening Energy Variance	53,443		53,443		3,875	3,875
1572-GLOBAL ADJUSTMENT		-64,228	-64,228		-4,657	-4,657
1580-RSVAWMS	76,395	-211,082	-134,687	-8,115	-9,765	-17,879
1582-RSVAONE-TIME	15,152	-5,631	9,521		1,507	1,507
1584-RSVANW	-320,573	-158,664	-479,237	-17,133	-34,745	-51,878
1586-RSVACN	-142,300	92,098	-50,202	-25,765	-3,640	-29,405
1588-RSVAPOWER	-190,974	217,261	26,287	-12,409	1,906	-10,503
1592-2006 PILs/Taxes Variance						
TOTAL	**-269,077**	**26,285**	**-242,792**	**-63,422**	**-22,734**	**-86,156**

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	1-Jan-2006 to 31-Dec-2006					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	126,438	3,169	129,607	6,366	5,821	12,187
1525-Miscellaneous Deferred Debits	56,057		56,057	4,064	2,883	6,947
1550-LV Variance Account		67,810	67,810		1,556	1,556
1555-Smart Meters Capital Variance Account		-15,343	-15,343		-337	-337
1556-Smart Meters OM&A Variance Account		643	643			
1562-Deferred Payments in Lieu of Taxes	-125,419	1,216	-124,203	-9,093	-6,387	-15,480
1565-Conservation and Demand Management Expenditures and Recoveries	-218,240	-20,972	-239,213			
1566-CDM Contra Account	218,240	20,972	239,213			
1570-Qualifying Transition Costs	339,236		339,236	21,447	15,213	36,660
1571-Pre-market Opening Energy Variance	53,443		53,443	3,875	2,748	6,623
1572-GLOBAL ADJUSTMENT	-64,228	350,759	286,531	-4,657	14,735	10,078
1580-RSVAWMS	-134,687	-490,038	-624,725	-17,879	-32,126	-50,006
1582-RSVAONE-TIME	9,521	12,200	21,721	1,507	1,117	2,624
1584-RSVANW	-479,237	-127,508	-606,745	-51,878	-31,202	-83,080
1586-RSVACN	-50,202	-284,118	-334,321	-29,405	-17,192	-46,597
1588-RSVAPOWER	26,287	-1,145,129	-1,118,842	-10,503	-57,536	-68,040
1592-2006 PILs/Taxes Variance						
TOTAL	**-242,792**	**-1,626,338**	**-1,869,130**	**-86,156**	**-100,709**	**-186,865**

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	1-Jan-2007 to 31-Dec-2007					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	129,607	-22,182	107,426	12,187	2,559	14,747
1525-Miscellaneous Deferred Debits	56,057	-56,057	-0	6,947	-6,947	0
1550-LV Variance Account	67,810	91,605	159,415	1,556	7,536	9,093
1555-Smart Meters Capital Variance Account	-15,343	66,468	51,125	-337	2,710	2,373
1556-Smart Meters OM&A Variance Account	643	5,563	6,206			
1562-Deferred Payments in Lieu of Taxes	-124,203		-124,203	-15,480	-5,872	-21,352
1565-Conservation and Demand Management Expenditures and Recoveries	-239,213	123,016	-116,197			
1566-CDM Contra Account	239,213	-123,016	116,197			
1570-Qualifying Transition Costs	339,236	-339,236	-0	36,660	-36,660	0
1571-Pre-market Opening Energy Variance	53,443	-53,443		6,623	-6,623	-0
1572-GLOBAL ADJUSTMENT	286,531	-117,646	168,885	10,078	7,984	18,062
1580-RSVAWMS	-624,725	-417,488	-1,042,213	-50,006	-32,634	-82,640
1582-RSVAONE-TIME	21,721	-21,721		2,624	-2,624	-0
1584-RSVANW	-606,745	405,652	-201,093	-83,080	37,268	-45,812
1586-RSVACN	-334,321	-408,397	-742,718	-46,597	28,828	-17,769
1588-RSVAPOWER	-1,118,842	699,918	-418,924	-68,040	16,328	-51,712
1592-2006 PILs/Taxes Variance						
TOTAL	**-1,869,130**	**-166,964**	**-2,036,094**	**-186,865**	**11,855**	**-175,009**

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	1-Jan-2008 to 31-Dec-2008					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	107,426		107,426	14,747	4,276	19,022
1525-Miscellaneous Deferred Debits	-0		-0	0		0
1550-LV Variance Account	159,415	88,541	247,956	9,093	9,869	18,961
1555-Smart Meters Capital Variance Account	51,125	45,338	96,463	2,373	3,839	6,212
1556-Smart Meters OM&A Variance Account	6,206	49,815	56,021		2,230	2,230
1562-Deferred Payments in Lieu of Taxes	-124,203		-124,203	-21,352	-4,943	-26,295
1565-Conservation and Demand Management Expenditures and Recoveries	-116,197	116,197	0			
1566-CDM Contra Account	116,197	-116,197	-0			
1570-Qualifying Transition Costs	-0		-0	0		0
1571-Pre-market Opening Energy Variance				-0		-0
1572-GLOBAL ADJUSTMENT	168,885	100,736	269,621	18,062	10,731	28,793
1580-RSVAWMS	-1,042,213	-430,673	-1,472,886	-82,640	-58,621	-141,261
1582-RSVAONE-TIME				-0		-0
1584-RSVANW	-201,093	-24,399	-225,492	-45,812	-8,975	-54,786
1586-RSVACN	-742,718	-352,468	-1,095,186	-17,769	-43,588	-61,357
1588-RSVAPOWER	-418,924	-124,999	-543,923	-51,712	-21,656	-73,368
1592-2006 PILs/Taxes Variance						
TOTAL	**-2,036,094**	**-648,110**	**-2,684,203**	**-175,009**	**-106,839**	**-281,849**

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	31-Dec-2008 Balance			1-Jan-09 to 30-Apr-09		
Deferral / Variance Account	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Regulatory Assets	107,426	19,022	126,448	877		127,325
1525-Miscellaneous Deferred Debits	-0	0	-0	-0		-0
1550-LV Variance Account	247,956	18,961	266,918	2,025	6,500	275,443
1555-Smart Meters Capital Variance Account	96,463	6,212	102,675	788	-5,847	97,616
1556-Smart Meters OM&A Variance Account	56,021	2,230	58,251	458	2,287	60,996
1562-Deferred Payments in Lieu of Taxes	-124,203	-26,295	-150,498	-1,014		-151,512
1565-Conservation and Demand Management Expenditures and Recoveries	0		0			0
1566-CDM Contra Account	-0		-0			-0
1570-Qualifying Transition Costs	-0	0	-0	-0		-0
1571-Pre-market Opening Energy Variance		-0	-0			-0
1572-GLOBAL ADJUSTMENT	269,621	28,793	298,414	2,202	706,946	1,007,562
1580-RSVAWMS	-1,472,886	-141,261	-1,614,147	-12,029	-201,498	-1,827,673
1582-RSVAONE-TIME		-0	-0			-0
1584-RSVANW	-225,492	-54,786	-280,278	-1,842	-54,543	-336,663
1586-RSVACN	-1,095,186	-61,357	-1,156,543	-8,944	-157,812	-1,323,299
1588-RSVAPOWER	-543,923	-73,368	-617,291	-4,442	-629,431	-1,251,164
1592-2006 PILs/Taxes Variance						
TOTAL	**-2,684,203**	**-281,849**	**-2,966,052**	**-21,921**	**-333,398**	**-3,321,371**

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	1-May-09 to 31-Dec-09			1-Jan-10 to 30-Apr-10		
Deferral / Variance Account	**Interest**	**Other**	**Balance**	**Interest**	**Other**	**Balance**
1508-Other Regulatory Assets	394	4,244	131,962	205		132,167
1525-Miscellaneous Deferred Debits	-0		-0	-0		-0
1550-LV Variance Account	1,267	34,973	311,683	531		312,214
1555-Smart Meters Capital Variance Account	6,321	534,372	638,309	1,146		639,455
1556-Smart Meters OM&A Variance Account	934	64,075	126,004	224		126,229
1562-Deferred Payments in Lieu of Taxes	-399		-151,911	-228		-152,139
1565-Conservation and Demand Management Expenditures and Recoveries			0			0
1566-CDM Contra Account			-0			-0
1570-Qualifying Transition Costs	-0		-0	-0		-0
1571-Pre-market Opening Energy Variance			-0			-0
1572-GLOBAL ADJUSTMENT	3,246	-497,634	513,174	878		514,052
1580-RSVAWMS	-9,994	-261,710	-2,099,377	-3,550		-2,102,927
1582-RSVAONE-TIME			-0			-0
1584-RSVANW	-910	38,122	-299,451	-444		-299,894
1586-RSVACN	-7,216	-167,666	-1,498,181	-2,605		-1,500,786
1588-RSVAPOWER	-8,872	1,666	-1,258,370	-2,148		-1,260,518
1592-2006 PILs/Taxes Variance	-9,800	-861,382	-871,182	-1,579		-872,761
TOTAL	**-25,028**	**-1,110,941**	**-4,457,340**	**-7,569**		**-4,464,909**

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.55%	31-Dec-08 Balance + Interest to 30-Apr-10			1-May-10 to 31-Dec-10		
Deferral / Variance Account	**31-Dec-08**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Regulatory Assets	126,448	1,476	127,924	409		132,577
1525-Miscellaneous Deferred Debits	-0	-0	-0	-0		-0
1550-LV Variance Account	266,918	3,823	270,740	1,061		313,275
1555-Smart Meters Capital Variance Account	102,675	8,255	110,930	2,292		641,747
1556-Smart Meters OM&A Variance Account	58,251	1,616	59,867	449		126,677
1562-Deferred Payments in Lieu of Taxes	-150,498	-1,641	-152,139	-455		-152,594
1565-Conservation and Demand Management Expenditures and Recoveries	0		0			0
1566-CDM Contra Account	-0		-0			-0
1570-Qualifying Transition Costs	-0	-0	-0	-0		-0
1571-Pre-market Opening Energy Variance	-0		-0			-0
1572-GLOBAL ADJUSTMENT	298,414	6,326	304,740	1,756		515,808
1580-RSVAWMS	-1,614,147	-25,572	-1,639,719	-7,099		-2,110,026
1582-RSVAONE-TIME	-0		-0			-0
1584-RSVANW	-280,278	-3,195	-283,473	-887		-300,781
1586-RSVACN	-1,156,543	-18,765	-1,175,308	-5,209		-1,505,995
1588-RSVAPOWER	-617,291	-15,462	-632,753	-4,296		-1,264,815
1592-2006 PILs/Taxes Variance		-11,379	-11,379	-3,158		-875,920
TOTAL	**-2,966,052**	**-54,518**	**-3,020,571**	**-15,138**		**-4,480,047**

Exhibit 9: Deferral And Variance Accounts

Tab 2 (of 3): Clearance of Deferral and Variance Accounts

SELECTION OF BALANCES FOR DISPOSITION

Attachment 1 presents the list of deferral and variance accounts, with the proposed selection of balances for disposition. All account balances selected for disposition are as at December 31, 2009; being the most recent date the balances were subject to audit. Additional interest to April 30, 2010 has also been included in the proposed amounts for disposition.

In Attachment 1, 'No Recovery' appears for the Global Adjustment sub-account of account 1588-RSVA/Power. In fact, ORPC does propose to dispose of the sub-account balance, but through a distinct rate rider as described in Exhibit 9, Tab 2, Schedule 2.

Board policy states: *at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline.*[1] The following accounts with non-zero balances have been excluded from ORPC's proposed dispositions:

Table 1: Accounts Excluded from Proposed Dispositions

Account(s)	Justification
1555-Smart Meters Capital Variance Account 1556-Smart Meters OM&A Variance Account	As at December 31, 2009, the utility had not reached the 50% threshold for deployment of smart meters, as required by Board policy prior to disposition of variance account balances [2]
1562-Deferred Payments in Lieu of Taxes 1592-PILS & Tax Variance for 2006 and Subsequent years	The requirements for the disposition of balances in account #1562 are the subject of an ongoing proceeding before the Board (EB-2008-0381). ORPC expects the outcome of that proceeding to be relevant to the requirements for the disposition of the balance in account #1592.

[1] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), July 31, 2009, page 13

[2] Guideline G-2008-0002: Smart Meter Funding and Cost Recovery, October 22, 2008, page 12

Proposed Deferral /Variance Account Balance Recoveries

Deferral / Variance Account	Recover Balance as at?	Additional Interest to 30 Apr/10?	Balance for Recovery [1]	Additional Interest for Recovery	Total Recovery Amount
1508-Other Regulatory Assets	31-Dec-09	YES	131,962	205	132,167
1525-Miscellaneous Deferred Debits	No Recovery				
1550-LV Variance Account	31-Dec-09	YES	311,683	531	312,214
1555-Smart Meters Capital Variance Account	No Recovery				
1556-Smart Meters OM&A Variance Account	No Recovery				
1562-Deferred Payments in Lieu of Taxes	No Recovery				
1565-Conservation and Demand Management Expenditures and Recoveries	No Recovery				
1566-CDM Contra Account	No Recovery				
1570-Qualifying Transition Costs	No Recovery				
1571-Pre-market Opening Energy Variance	No Recovery				
1572-GLOBAL ADJUSTMENT	No Recovery				
1580-RSVAWMS	31-Dec-09	YES	-2,099,377	-3,550	-2,102,927
1582-RSVAONE-TIME	No Recovery				
1584-RSVANW	31-Dec-09	YES	-299,451	-444	-299,894
1586-RSVACN	31-Dec-09	YES	-1,498,181	-2,605	-1,500,786
1588-RSVAPOWER	31-Dec-09	YES	-1,258,370	-2,148	-1,260,518
1592-2006 PILs/Taxes Variance	No Recovery				
Sub-Total for Recovery					**-4,719,744**
1590-Recovery of Regulatory Asset Balances (residual)	31-Dec-09	YES	-125,991	-231	-126,222
Total Recoveries Required					**-4,845,967**
Annual Recovery Amounts **# years:**	**4**				**-1,211,492**

[1] per sheet B5, except account 1590 (sheet C5)

CALCULATION OF RATE RIDERS

Attachment 1 shows the calculation of the proposed rate rider to dispose of the balance in account 1588-RSVA/Power, sub-account Global Adjustment. A distinct rate rider for this disposition would be charged only to non-RPP, non-MUSH[1] customers, whose energy billings gave rise to the balance. The disposition would take place over 12 months, the default period established by the Board.[2]

Attachment 2 shows the calculation of the proposed rate riders to dispose of all other deferral and variance accounts selected for disposition, as explained in the previous schedule. The amounts for disposition have been allocated to individual customer classes using the allocators prescribed by the Board.[3]

A disposition period of four years is proposed, due to the significant credit balances which have accumulated in the RSVA accounts. There are two primary justifications for the departure from the Board's 12-month default period for disposition. First, the large credit rate riders for a 12-month disposition would lead to an anomalous rate outcome: many customers would experience little if any sensitivity to volume in their delivery charges, or even total delivery charges that decrease under higher volumes. Second, the four year disposition would mitigate rate volatility for customers, which would be more severe under a shorter disposition period as the rate rider is implemented and then expires. The Board has previously agreed that minimizing rate volatility is a key regulatory principle.[4]

A longer disposition period also increases inter-generational inequity, contrary to another key regulatory principle. However, in this instance, ORPC submits the anomalous rate

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[1] RPP: Regulated Price Plan; MUSH: Municipalities, Universities, Schools & Hospitals
[2] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), July 31, 2009, page 24
[3] *ibid.*, pages 21-22
[4] Report of the Board: Transition to International Financial Reporting Standards (EB-2008-0408), July 28, 2009, page 7

outcome and degree of rate volatility constitute more important considerations, in determining the most appropriate disposition period.

Attachment 3 presents the same information as Attachment 2, but assumes (for illustrative purpose only) that RSVA accounts were excluded from the proposed dispositions.

Global Adjustment Rate Rider

Per Sheet B5:	**Principal**	**Interest**	**Total**
Balance for Recovery (31-Dec-2009):	478,933	34,241	513,174
Additional Interest to 30-Apr-2010		878	878
Total for Recovery	**478,933**	**35,119**	**514,052**
Years for Recovery			1
Annual Recovery			514,052
Non-RPP, non-MUSH kWh's (2009 Actual)			48,935,564
GA Rate Rider, per kWh *			**$0.0105**

** Applies to non-RPP, non-MUSH customers only*

Table of Proposed Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load
1508-Other Regulatory Assets	132,167	Distribution Revenue (existing rates)	74,324	23,489	31,682	811
1550-LV Variance Account	312,214	kWh's	125,365	56,890	125,046	690
1580-RSVAWMS	-2,102,927	kWh's	-844,400	-383,182	-842,249	-4,649
1584-RSVANW	-299,894	kWh's	-120,418	-54,645	-120,112	-663
1586-RSVACN	-1,500,786	kWh's	-602,619	-273,464	-601,084	-3,318
1588-RSVAPOWER	-1,260,518	kWh's	-506,143	-229,683	-504,854	-2,787
Sub-Total for recovery	**-4,719,744**		**-1,873,892**	**-860,595**	**-1,911,571**	**-9,915**
1590-Recovery of Regulatory Asset Balances (residual)	-126,222	2006 EDR Approved Recoveries	-1,790,960	295,070	1,306,812	
Total Recoveries Required (4 years)	**-4,845,967**		**-3,664,852**	**-565,525**	**-604,758**	**-9,915**
Annual Recovery Amounts	-1,211,492		-916,213	-141,381	-151,190	-2,479
Annual Volume			79,547,654	36,098,055	211,781	437,952
Proposed Rate Rider			**($0.0115)**	**($0.0039)**	**($0.7139)**	**($0.0057)**
per			kWh	kWh	kW	kWh

[1] per sheet C6

Table of Proposed Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting
1508-Other Regulatory Assets	132,167	Distribution Revenue (existing rates)	237	1,624
1550-LV Variance Account	312,214	kWh's	418	3,805
1580-RSVAWMS	-2,102,927	kWh's	-2,817	-25,630
1584-RSVANW	-299,894	kWh's	-402	-3,655
1586-RSVACN	-1,500,786	kWh's	-2,010	-18,291
1588-RSVAPOWER	-1,260,518	kWh's	-1,688	-15,363
Sub-Total for recovery	**-4,719,744**		**-6,262**	-57,510
1590-Recovery of Regulatory Asset Balances (residual)	-126,222	2006 EDR Approved Recoveries	-8,857	71,712
Total Recoveries Required (4 years)	**-4,845,967**		**-15,119**	14,202
Annual Recovery Amounts	-1,211,492		-3,780	3,551
Annual Volume			760	6,853
Proposed Rate Rider per			**($4.9734)** kW	**$0.5181** kW

[1] per sheet C6

Table of Proposed Rate Riders

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load
Customers / Connections	C1	13,371	8,895	1,391	144	73
kWh's	C1	198,108,544	79,547,654	36,098,055	79,345,026	437,952
Distribution Revenue (existing rates)	C4	3,789,939	2,131,264	673,547	908,501	23,266
Distribution Revenue (proposed rates)	F4	3,972,542	2,412,448	735,366	726,603	5,920
Transmission Connection Revenue	C2	449,924	189,638	78,573	175,863	953
2009 Non-RPP, Non-MUSH kWh's	ElecPrice	48,935,564	8,642,886	2,796,427	37,122,994	
2006 EDR Approved Recoveries	2006 EDR	11,597	164,555	-27,111	-120,071	
Approved Recoveries	C5					

Table of Proposed Rate Riders

Allocators	Data Source	2010 Projection Total	Sentinel Lighting	Street Lighting
Customers / Connections	C1	13,371	216	2,653
kWh's	C1	198,108,544	265,370	2,414,487
Distribution Revenue (existing rates)	C4	3,789,939	6,802	46,558
Distribution Revenue (proposed rates)	F4	3,972,542	12,885	79,319
Transmission Connection Revenue	C2	449,924	498	4,400
2009 Non-RPP, Non-MUSH kWh's	ElecPrice	48,935,564	34,234	339,023
2006 EDR Approved Recoveries	2006 EDR	11,597	814	-6,589
Approved Recoveries	C5			

Table of Proposed Rate Riders excluding RSVA accounts

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load
1508-Other Regulatory Assets	132,167	Distribution Revenue (existing rates)	74,324	23,489	31,682	811
1550-LV Variance Account	312,214	kWh's	125,365	56,890	125,046	690
Sub-Total for recovery	**444,381**		**199,689**	**80,378**	**156,728**	**1,502**
1590-Recovery of Regulatory Asset Balances (residual)	-126,222	2006 EDR Approved Recoveries	-1,790,960	295,070	1,306,812	
Total Recoveries Required (4 years)	**318,159**		**-1,591,271**	**375,448**	**1,463,540**	**1,502**
Annual Recovery Amounts	79,540		-397,818	93,862	365,885	375
Annual Volume			79,547,654	36,098,055	211,781	437,952
Proposed Rate Rider			**($0.0050)**	**$0.0026**	**$1.7277**	**$0.0009**
per			kWh	kWh	kW	kWh

[1] per sheet C6

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load
kWh's	C1	198,108,544	79,547,654	36,098,055	79,345,026	437,952
Distribution Revenue (existing rates)	C4	3,789,939	2,131,264	673,547	908,501	23,266
2006 EDR Approved Recoveries	2006 EDR	11,597	164,555	-27,111	-120,071	

Table of Proposed Rate Riders excluding RSVA accounts

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Sentinel Lighting	Street Lighting
1508-Other Regulatory Assets	132,167	Distribution Revenue (existing rates)	237	1,624
1550-LV Variance Account	312,214	kWh's	418	3,805
Sub-Total for recovery	**444,381**		**655**	5,429
1590-Recovery of Regulatory Asset Balances (residual)	-126,222	2006 EDR Approved Recoveries	-8,857	71,712
Total Recoveries Required (4 years)	**318,159**		**-8,202**	77,141
Annual Recovery Amounts	79,540		-2,050	19,285
Annual Volume			760	6,853
Proposed Rate Rider			**($2.6980)**	**$2.8141**
per			kW	kW

[1] per sheet C6

Allocators	Data Source	2010 Projection Total	Sentinel Lighting	Street Lighting
kWh's	C1	198,108,544	265,370	2,414,487
Distribution Revenue (existing rates)	C4	3,789,939	6,802	46,558
2006 EDR Approved Recoveries	2006 EDR	11,597	814	-6,589

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 3): Smart Meters

SMART METER DEPLOYMENT PLAN STATUS

Attachment 1 summarizes the number of smart meters installed and amounts recorded to the related variance accounts.

ORPC began a smart meter pilot project in 2007, following the Board's approval to reallocate funds from another program under the Third Tranche funding for Conservation and Demand Management programs.[1] The project was carried out in accordance with Ontario Regulation 153/07, Section 1(1), Paragraph 4. The Elster Metering system was selected for the pilot, after having been approved under the procurement process carried out by the Coalition of Large Distributors. The pilot project involved the installation of approximately 350 meters in the Pembroke service area, along with a MAS system for the communication and collection of data. In 2008, an additional 203 smart meters were installed in the Pembroke area under this pilot project.

In 2009, ORPC entered into a contract with Elster Metering for the full implementation of smart meters, following participation in the London RFP Procurement Process. By the end of that year, smart meters were 100% installed in ORPC's Beachburg and Killaloe service areas. Implementation began in the Almonte service area and continued in the Pembroke service area. In total, ORPC installed 3,156 smart meters in 2009.

That same year, ORPC spearheaded a cost sharing contract with other electricity distributors in the region. As ORPC had purchased a MAS server under third tranche funding, it was felt that a group of utilities could benefit from the use of this. Under this arrangement Renfrew Hydro, Hydro 2000, Co-operative Embrun, Hawksbury Hydro and Ottawa River Power Corporation now share many costs of operating.

In 2010, the remaining 6,500 meters will be installed. As of May 15th, another 2,311 had been installed.

[1] see EB-2006-0350

To date no work has been completed on the integration of meters and systems with the provincial Meter Data Management Repository ("MDMR"). ORPC staff have attended MDMR briefings and workshops. ORPC expects the integration will commence in late 2010 with completion in early 2011.

Smart Meter Summary Information

Year	Smart meters Installed			% of customers converted	Account 1555		Account 1556
	Residential	GS<50	Other		Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses
2006	-	-	-	0.0%			
2007	350	-	-	4.0%	45,821	72,733	643
2008	203	-		2.3%	35,265	111,604	28,884
2009	2,997	159		31.0%	93,599	411,895	28,956
2010	5,250	1,241		62.7%	94,000	847,140	30,000
Total	**8,800**	**1,400**	**-**	**100.0%**	**268,685**	**1,443,372**	**88,484**

SMART METER FUNDING ADDER AMOUNTS

The existing approved Monthly Service Charge for metered customer classes includes a generic funding adder of $1.00 for the deployment of smart meters. Since the deployment of smart meters is expected to be completed in 2010, ORPC proposes to replace this adder with an amount based on utility-specific costs.

Attachment 1 presents the calculation of its proposed funding adder for metered customer classes, which would be included in the Monthly Service Charge.

ORPC proposes to retain this adder until May 1, 2012. The utility expects that the 2012 rate year will be its earliest opportunity for the disposition of its Smart Meters variance accounts to take effect, or to implement a revised adder amount if necessary.

Smart Meter Costs for 2010 EDR funding adder

2010 EDR Data Information

Long-term debt	56.0%
Short-term debt	4.0%
Deemed Equity	40.0%
Deemed long-term debt rate	7.25%
Short-term debt rate	2.07%
Return on Equity	9.85%
Weighted Average Cost of Capital	8.08%

2010 Tax Rate

Corporate Income Tax Rate	16.00%
Capital Tax Rate	0.000%

Capital Data:

	to 31-Dec-08	01-Jan-09 to 31-Dec-09	01-Jan-10 to 31-Dec-10
Smart meter including installation	$ 130,582	$ 402,595	$ 847,140
Tools and Equipment (Work force management)		$ 9,300	$ -
Computer Hardware Costs	$ 16,585	$ -	$ -
Computer Software	$ 37,170	$ -	$ -
Total Capital Costs	$ 184,337	$ 411,895	$ 847,140

LDC Amortization Policy:

Smart Meter Amortization Rate	$ 15	Years
Tools and Equipment (Work force management)	$ 10	Years
Computer Hardware Amortization Rate	$ 5	Years
Computer Software Amortization Rate	$ 3	Years

Operating Expense Data:

	01-Jan-10 to 31-Dec-10
Incremental OM&A Expenses	$ 30,000
Total Incremental Operating Expense	$ 30,000

Smart Meter Costs for 2010 EDR funding adder

Average Asset Values	**31-Dec-10**		
Net Fixed Assets Smart Meters	$ 898,377		
Net Fixed Assets Tools and Equipment	$ 4,573		
Net Fixed Assets Computer Hardware	$ 13,268		
Net Fixed Assets Computer Software	$ 12,390		
Total Net Fixed Assets	$ 928,608	$ 928,608	
Working Capital			
Operation Expense	$ 30,000		
15 % Working Capital	$ 4,500	$ 4,500	
Smart Meters included in Rate Base		$ 933,108	
Return on Rate Base			
Long-term debt	56.0%	$ 522,540	
Short-term debt	4.0%	$ 37,324	
Deemed Equity	40.0%	$ 373,243	
		$ 933,108	
Deemed long-term debt rate	7.25%	$ 37,884	
Short-term debt rate	2.07%	$ 773	
Return on Equity	9.85%	$ 36,764	
Return on Rate Base		$ 75,421	$ 75,421
Operating Expenses			
Incremental Operating Expenses			$ 30,000

Smart Meter Costs for 2010 EDR funding adder

Amortization Expenses				
Amortization Expenses - Smart Meters	$	63,783		
Amortization Expenses - Tools and equirement	$	155		
Amortization Expenses - Computer Hardware	$	3,317		
Amortization Expenses - Computer Software	$	12,390		
Total Amortization Expenses			$	79,645
Revenue Requirement Before PILs			$	185,066
Calculation of pre-tax income				
Incremental Operating Expenses			-$	30,000
Depreciation Expenses			-$	79,645
Interest Expense			-$	38,657
Pre-tax Income For PILs			$	36,764
Grossed up PILs			$	7,115
Revenue Requirement Before PILs			$	185,066
Grossed up PILs			$	7,115
Revenue Requirement for Smart Meters			**$**	**192,181**
Net Revenue Requirement for 2010			**$**	**192,181**
Average customer #				10,429
2010 Funding Adder per month per metered customer				$1.54

Smart Meter Costs for 2010 EDR funding adder

		31-Dec-10
INCOME TAX		
Pre-tax Income	$	36,764
Amortization	$	79,645
CCA - Class 1 (8%) Smart Meters	-$	74,031
CCA - Class 8 (20%) Tools and Equipment	-$	1,674
CCA - Class 50 (55%) Computers	-$	3,352
CCA - Class 12 (100%) Computers Software	$	-
Change in taxable income	$	37,352
Tax Rate		16.00%
Income Taxes Payable	$	5,976
ONTARIO CAPITAL TAX		
Smart Meters	$	1,290,055
Tools and Equipment	$	9,145
Computer Hardware	$	11,610
Computer Software	$	6,195
Rate Base	$	1,317,005
Less: Exemption	$	-
Deemed Taxable Capital	$	1,317,005
Ontario Capital Tax Rate		0.000%
Net Amount (Taxable Capital x Rate)	$	-

Gross Up

	PILs Payable		Gross Up	Grossed Up PILs	
Change in Income Taxes Payable	$	5,976	16.00%	$	7,115
Change in OCT	$	-		$	-
PIL's	$	5,976		**$**	**7,115**

Smart Meter Costs for 2010 EDR funding adder

Net Fixed Assets - Smart Meters	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ 130,582	$ 533,176
Capital Investment Year 1	$ 130,582		
Capital Investment Year 2		$ 402,595	
Capital Investment Subsequent Years			$ 847,140
Closing Capital Investment	$ 130,582	$ 533,176	$ 1,380,316
Opening Accumulated Amortization	$ -	$ 4,353	$ 26,478
Amortization Year 1 (15 Years Straight Line)	$ 4,353	$ 8,705	$ 35,545
Amortization Subsequent Years		$ 13,420	$ 28,238
Closing Accumulated Amortization	$ 4,353	$ 26,478	$ 90,261
Opening Net Fixed Assets	$ -	$ 126,229	$ 506,698
Closing Net Fixed Assets	$ 126,229	$ 506,698	$ 1,290,055
Average Net Fixed Assets	$ 63,114	$ 316,464	$ 898,377

Net Fixed Assets - Tools and Equipment	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ 9,300
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ 9,300	$ -
Closing Capital Investment	$ -	$ 9,300	$ 9,300
Opening Accumulated Amortization	$ -	$ -	$ 155
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ 310
Amortization Year 2 (10 Years Straight Line)		$ 155	$ -
Closing Accumulated Amortization	$ -	$ 155	$ 465
Opening Net Fixed Assets	$ -	$ -	$ 9,145
Closing Net Fixed Assets	$ -	$ 9,145	$ 8,835
Average Net Fixed Assets	$ -	$ 4,573	$ 8,990

Smart Meter Costs for 2010 EDR funding adder

Net Fixed Assets - Computer Hardware	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ 16,585	$ 16,585
Capital Investment Year 1	$ 16,585		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ 16,585	$ 16,585	$ 16,585
Opening Accumulated Amortization	$ -	$ 1,659	$ 4,976
Amortization Year 1 (5 Years Straight Line)	$ 1,659	$ 3,317	$ 3,317
Amortization Year 2 (5 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ 1,659	$ 4,976	$ 8,293
Opening Net Fixed Assets	$ -	$ 14,927	$ 11,610
Closing Net Fixed Assets	$ 14,927	$ 11,610	$ 8,293
Average Net Fixed Assets	$ 7,463	$ 13,268	$ 9,951

Net Fixed Assets - Computer Software	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ 37,170	$ 37,170
Capital Investment Year 1	$ 37,170		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ 37,170	$ 37,170	$ 37,170
Opening Accumulated Amortization	$ -	$ 6,195	$ 18,585
Amortization Year 1 (3 Years Straight Line)	$ 6,195	$ 12,390	$ 12,390
Amortization Year 2 (3 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ 6,195	$ 18,585	$ 30,975
Opening Net Fixed Assets	$ -	$ 30,975	$ 18,585
Closing Net Fixed Assets	$ 30,975	$ 18,585	$ 6,195
Average Net Fixed Assets	$ 15,488	$ 24,780	$ 12,390

Smart Meter Costs for 2010 EDR funding adder

Total Assets

Total Fixed Assets	$ 184,337	$ 596,232	$ 1,443,372
Total Accumulated Amortization	$ 12,206	$ 50,194	$ 129,994
Closing Net Fixed Assets	$ 172,131	$ 546,038	$ 1,313,378

Smart Meter Costs for 2010 EDR funding adder

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ 125,358	$ 501,821
Capital Additions	$ 130,582	$ 402,595	$ 847,140
UCC Before Half Year Rule	$ 130,582	$ 527,953	$ 1,348,961
Half Year Rule (1/2 Additions - Disposals)	$ 65,291	$ 201,297	$ 423,570
Reduced UCC	$ 65,291	$ 326,656	$ 925,391
CCA Rate Class 47	8%	8%	8%
CCA	$ 5,223	$ 26,132	$ 74,031
Closing UCC	$ 125,358	$ 501,821	$ 1,274,929

UCC - Tools and Equipment

CCA Class 8 (20%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ 8,370
Capital Additions	$ -	$ 9,300	$ -
UCC Before Half Year Rule	$ -	$ 9,300	$ 8,370
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 4,650	$ -
Reduced UCC	$ -	$ 4,650	$ 8,370
CCA Rate Class 10	20%	20%	20%
CCA	$ -	$ 930	$ 1,674
Closing UCC	$ -	$ 8,370	$ 6,696

Smart Meter Costs for 2010 EDR funding adder

UCC - Computer Equipment

CCA Class 50 (55%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ 13,545	$ 6,095
Capital Additions Hardware	$ 16,585	$ -	$ -
Capital Additions Software			
UCC Before Half Year Rule	$ 16,585	$ 13,545	$ 6,095
Half Year Rule (1/2 Additions - Disposals)	$ 8,293	$ -	$ -
Reduced UCC	$ 8,293	$ 13,545	$ 6,095
CCA Rate Class 50	55%	55%	55%
CCA	$ 3,041	$ 7,450	$ 3,352
Closing UCC	$ 13,545	$ 6,095	$ 2,743

UCC - Computer Software

CCA Class 12 (100%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ 24,780	$ -
Capital Additions Hardware			
Capital Additions Software	$ 37,170	$ -	$ -
UCC Before Half Year Rule	$ 37,170	$ 24,780	$ -
Half Year Rule (1/2 Additions - Disposals)	$ 18,585	$ -	$ -
Reduced UCC	$ 18,585	$ 24,780	$ -
CCA Rate Class 12	100%	100%	100%
CCA	$ 12,390	$ 24,780	$ -
Closing UCC	$ 24,780	$ -	$ -