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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

November 28, 2008

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

Dear Ms. Walli:

EB-2008-0232 – Hydro One Remote Communities 2009 Distribution Rate Application – Evidence Update Filing

I am attaching three (3) paper copies of the Hydro One Remote Communities updates to the Prefiled Evidence seeking approval of the 2009 revenue requirement and customer rates for the distribution and generation of electricity.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

The update decreases 2009 Test Year revenue requirement by $2.7 million, which results in a decrease of $2.3 million to the requested level of Rural and Remote Rate Protection (RRRP). The material provided with this update will contribute to the accuracy and completeness of the evidence in this application, and covers the following items:

1. The community of Marten Falls is included in Remotes' service territory effective July 1, 2009. The original application included the community as of October 1, 2008.
2. The Renewable Energy Partnership program has been moved from a 2009 capital expenditure to 2009 OM&A to more accurately reflect the work which Remotes anticipates committing to this project.
3. 2008 and 2009 diesel fuel costs have been updated to reflect current forecast costs.
4. 2008 capital expenditures have been updated to reflect Remotes' current year-end projections.

5. Corrections to the pre-filed evidence.

In updating the evidence, Remotes has used the Board's materiality threshold of 1% of OM&A and 1% Net Fixed Assets to determine which areas of the evidence to update. Thus, items such as working capital, depreciation and accumulated depreciation were not updated as they did not meet this materiality threshold.

To facilitate the integration of this update into your copies of pre-filed evidence, we are attaching an Application Update Instruction.

Hydro One Networks will post electronic copies of the update on the Hydro One Networks' website for public access. In addition, one copy is being provided for public access at each of the following Hydro One Remote Communities Office –

Hydro One Remote Communities Office, 8th Floor, South Tower, 483 Bay Street, Toronto, Ontario

Hydro One Remote Communities Office, 680 Beaverhall Place, Thunder Bay, Ontario

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

cc. EB-2008-0232 Intervenors

EB-2008-0232 – Application Update Instruction[1]

Exhibit A, Tab 1, Schedule 1	Update page 1 to 4
Exhibit A, Tab 2, Schedule 1	Update pages 1 to 4
Exhibit A, Tab 2, Schedule 2	Update pages 1 to 4
Exhibit A, Tab 3, Schedule 1	Update pages 5, 6, 7
Exhibit A, Tab 13, Schedule 1 Appendix A	Update pages 1, 2
Exhibit C1, Tab 1, Schedule 1	Update pages 1 to 3
Exhibit C1, Tab 2, Schedule 1	Update pages 1 to 5
Exhibit C1, Tab 2, Schedule 2	Update pages 1 to 9
Exhibit C1, Tab 4, Schedule 1	Update pages 1 to 3
Exhibit C2, Tab 1, Schedule 1	Update page 1
Exhibit C2, Tab 2, Schedule 1	Update page 1
Exhibit C2, Tab 6, Schedule 1 Attachments	Update pages 1,2
Exhibit D1, Tab 1, Schedule 1	Update pages 1 to 3
Exhibit D1, Tab 2, Schedule 1	Update pages 1, 2, 5, 6, 7, 8
Exhibit D2, Tab 1, Schedule 1	Update page 1
Exhibit D2, Tab 2, Schedule 1	Update page 1
Exhibit D2, Tab 2, Schedule 2	Update pages 1 to 2
Exhibit D2, Tab 2, Schedule 3	Update page 1, Remove page 9 (G8)
Exhibit D2, Tab 2, Schedule 4	Update page 1
Exhibit D2, Tab 3, Schedule 1	Update page 1
Exhibit D2, Tab 3, Schedule 3	Update page 1
Exhibit E1, Tab 1, Schedule 1	Update pages 1 to 3
Exhibit E2, Tab 1, Schedule 1	Update page 1
Exhibit F1, Tab 1, Schedule 1	Update page 1
Exhibit G1, Tab 1, Schedule 2	Update page 3 to 6

[1] Note: not all pages have revisions but have been included for convenience.

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Remote Communities Inc. for an Order or Orders approving rates for the distribution of electricity.

APPLICATION

1. The Applicant is Hydro One Remote Communities Inc., a subsidiary of Hydro One Inc. The Applicant, which will hereinafter be referred to as "Remotes" is an Ontario corporation with its head office in Toronto. The Applicant is an integrated generation and distribution company licensed to generate and distribute electricity within 20 isolated communities in northern Ontario.

2. Remotes hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 78 of the *Ontario Energy Board Act, 1998,* for an Order or Orders approving the 2009 revenue requirement and customer rates for the distribution and generation of electricity.

3. Remotes seeks approval of a revenue requirement of $42,500 thousand for the Test Year 2009, of which $14,655 thousand is proposed to be recovered through customer rates leaving $27,845 thousand to be recovered from Rural and Remote Rate Protection (RRRP).

4. Remotes seeks approval to recover the December 31, 2008 forecast balance in the Rural and Remote Rate Protection Variance Account through RRRP rates. This

balance of $4,013 thousand would be added to the $27,845 thousand for recovery from all electricity users in the grid-connected part of the Province. Remotes is requesting the $31,858 thousand in RRRP to be established effective January 1, 2009.

5. Remotes seeks approval to retain the Rural and Remote Rate Protection Variance Account to mitigate risks related to increased costs and to recover the existing deficit balance. Remotes expects to report on this variance account annually, and will request any required change in the RRRP amount for Remotes at that time.

6. Remotes seeks approval of rates for residential, general service and standard A customers. These proposed rates continue to encourage conservation with the inclining block structure, originally established in 2006.

7. Remotes is a unique distributor in Ontario and is exempt from a number of the legal and regulatory requirements imposed on most distributors. Remotes generates electricity at diesel generating stations in certain isolated communities in the far north and distributes the electricity to customers in each community.

8. This application also seeks approval for cost increases related to the inclusion of the community of Marten Falls in Remotes' service territory, commencing July 1, 2009. The inclusion of new communities was identified as an upcoming cost pressure in the 2005 submission. An agreement to include Marten Falls in Remotes' service territory has been reached between the community and Remotes, subject to approval and agreement with the federal department of Indian and Northern Affairs Canada ("INAC"). Although Remotes intends to file a separate submission with the Board for approval to the change in its service

territory, the costs to serve this community starting July 1, 2009 are included in this submission for the 2009 Test Year.

9. The written evidence filed with the Board may be amended from time to time prior to the Board's final decision on the Application. Further, the Applicant may seek meetings with Board staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

10. The persons affected by this Application are the ratepayers of Remotes and of RRRP. It is impractical to set out their names and addresses because they are too numerous.

11. Remotes requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Mr. Glen MacDonald
Senior Advisor – Regulatory Affairs
Hydro One Networks Inc.

Address for personal service:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-5913
Fax:	(416) 345-5866
Electronic access:	glen.e.macdonald@HydroOne.com

b) The Applicant's counsel:

Mr. John D. Strung
Rogers Partners LLP

Mailing Address:	181 University Avenue, Suite 1900, Toronto, Ontario M5H 3M7
Telephone:	(416) 594-4503
Fax:	(416) 594-9100
Electronic access:	john.strung@rogerspartners.com

DATED at Toronto, Ontario, this 29th day of August, 2008.

HYDRO ONE NETWORKS INC.

By its counsel,

____

John D. Strung

SUMMARY OF APPLICATION

Hydro One Remote Communities ("Remotes") is an integrated generation and distribution company licensed to generate and distribute electricity within 20 isolated communities in northern Ontario. Consistent with the Board's decision in RP-1998-0001, Remotes is 100% debt financed and is operated as a break-even company with no return on equity.

This application seeks to establish a new revenue requirement for Remotes based on the methodology and principles set out in the *OEB Filing Requirements for Transmission and Distribution Applications* issued November 14, 2006. The application is based on a forward-looking 2009 test year. Because Remotes remains an integrated generation and distribution company, the application includes both generation and distribution related costs. Remotes does not plan to seek a return on equity, and the application reflects the break-even basis of the Remotes business consistent with the OEB approval for 2006 rates.

Since Remotes' last rate application three years ago, major changes have occurred that affect Remotes' operations. Most notably, diesel fuel prices have continued to increase. These increases have led to major cost pressures, as diesel generation is the primary source of electricity in Remotes' service territory. In addition, higher fuel prices increase the cost to transport staff, material and equipment.

Remotes is also facing cost pressures related to customer arrears, ongoing inflation, increased safety and environmental regulation, and industry-wide shortages of skilled workers, in particular, skilled trades staff.

Remotes undertook several strategies to mitigate the impact of cost pressures on customers, including more intensive coordination of flights to transport staff and equipment, renegotiated fuel supply contracts, increased use of winter roads for the transportation of fuel and equipment, improved customer collections, the customer CDM program and new standards for station efficiency. These efforts are planned to be continued in the 2009 Test Year.

This application seeks to establish a new revenue requirement of $42,500 thousand, to address the increases in diesel and operating costs, while also incorporating the above noted productivity improvements. The Board of Directors of Remotes and Hydro One Inc. have approved the 2009 business plan on which this application is based.

This application also seeks approval for cost increases related to the inclusion of the community of Marten Falls in Remotes' service territory commencing July 1, 2009. The inclusion of new communities was identified as an upcoming cost pressure in the 2005 submission. An agreement to include Marten Falls in Remotes' service territory has been reached between the community and Remotes, subject to approval and agreement with INAC, which is anticipated to be forthcoming. There is some uncertainty associated with the timing of Marten Falls' inclusion in Remotes service territory, as there are four preconditions in the agreement. First, the agreement must be signed by all three parties; second, the fuel tanks and fuel offload system replacement (currently underway) must be complete; third, the provincial government must agree to the change to Remotes' service territory; and fourth, the Remotes' licence must be amended to include the community. We anticipate that these pre-conditions will be satisfied by July 1, 2009. The inclusion of Marten Falls on July 1, 2009, has added approximately $666 thousand to 2009 revenue requirement, or $406 thousand net of revenue from Marten Falls customers, which is forecast to be $261 thousand. Although Remotes intends to file a separate submission with the Board for approval to change its licence and service territory, the costs to serve this community are included in this submission.

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the *Ontario Energy Board Act, 1998*. O. Reg. 442/01 under that statute requires the Board to calculate Rate Protection for these customers and requires that Remotes charge rates that are not based on the cost of service.

Remotes' last rate application, RP-2005-0020/EB-2005/0497 filed October 26, 2005 for a 2006 Test Year, made energy conservation a key element of Remotes' approach to meeting electrical needs in its service territory by introducing an inclining block rate structure and by implementing an ongoing Conservation and Demand Management ("CDM") program. The application, based on 2004 historical costs, did not request an increase in the overall revenue requirement that was set in 2002.

For the 2009 Test Year, Remotes is proposing to increase rates to the average customer in its service territory by 4.4%, the average increase for grid connected customers approved by the Board in 2008, based on applications to-date. In 2006, the Board approved an inclining block rate structure for Remotes' Year Round Residential (R2), Residential Seasonal (R4), General Service Single Phase (G1) and General Service Three-Phase (G3) customers. The inclining blocks were designed such that customers with very high usage would be subject to a price signal to encourage conservation. Remotes is proposing to bring the third and final block of usage up to cost over time, and is therefore proposing a 25% increase to rates for the final block at this time. Future rate increases to this block would be determined in other proceedings.

Remotes' Rate Protection has remained unchanged for the past six years at $21.1 million per year, an amount established in 2002. Based on its forecast costs for 2009, Remotes is requesting approval to increase the level of Rate Protection in 2009 to $27.8 million. This increase is primarily due to the increase in diesel fuel prices.

In 2003 Remotes established a balance sheet revenue variance account to track differences between its revenues and costs, the RRRP variance account. This account is now in a deficit position. Remotes is requesting recovery of this balance be added to the amount to be recovered through RRRP rates, which will result in $31,858 thousand to be funded through RRRP rates. Remotes is also requesting to retain the Rural and Remote Rate Protection Variance Account to track variances between future revenues and costs.

In summary, Hydro One Remote Communities is seeking the Board's approval for the following items:

- Remotes' 2009 Test Year Revenue Requirement of $42,500 thousand
- Approval to establish Rural and Remote Rate Protection for 2009 at $31,858 thousand
- Approval for 2009 customer rates
- Approval to retain the RRRP variance account for the 2009 Test and subsequent years.

FINANCIAL SUMMARY

1.0 INTRODUCTION

Remotes is making this application in accordance with the requirements of the Ontario Energy Board *Filing Requirements for Transmission and Distribution Applications* issued November 14, 2006. The proposed revenue requirement and rates included in this application have been prepared on the basis of a forward-looking 2009 test year. This submission also includes information for a 2008 bridge year, historical information for 2005, 2006 and 2007, and historic Board approved 2006 year. Given that Remotes' previous rate submission was based on a 2006 test year using 2004 actuals, there is a 5-year timing difference between test years. This timing lag should be kept in mind when making comparisons.

Remotes is proposing to recover a total revenue requirement of $42,500 thousand from its customers and from the Rural and Remote Rate Protection fund for the 2009 test year. This represents an increase of $6,949 thousand, or 20% over the 2006 approved revenue requirement. Calculation of the revenue requirement appears in the evidence at Exhibit E2, Tab 1, Schedule 1.

The following table summarizes the financial highlights for the 2009 test year.

Financial Highlights

	$000s	*Exhibit*
Total OM&A Expense	36,016	C1-2-1
Depreciation	4,469	C1-4-1
Rate Base	30,326	D1-1-1
Return on Rate Base	1,720	D1-1-1
Revenue Requirement	42,500	E1-1-1
Capital Expenditures	5,138	D1-2-1
Regulatory Assets	4,013	F1-1-1
Remote Rate Protection	27,845	F1-1-1

Remotes Operations, Maintenance and Administration (“OM&A”) expenditures have been determined on the basis of an examination of required work programs to ensure the appropriate and cost-effective solutions are implemented. A description of Remotes’ planning process is provided at Exhibit A, Tab 13, Schedule 1. The proposed OM&A expenditures are $36,016 thousand and include $21,649 thousand for diesel fuel required to generate electricity. This represents a fuel cost increase of $3,744 thousand or 21% over the 2006 OEB-approved amount. The proposed OM&A expenditures are driven by such factors as the need to meet customer, regulatory and statutory requirements regarding service and reliability. These expenditures are itemized at Exhibit C2, Tab 2, Schedule 1 and discussed in written direct evidence at Exhibit C1, Tabs 1 and 2. The costs of shared services have been allocated to Remotes by Hydro One using the Corporate Cost Allocation Methodology, approved in Hydro One Networks 2006 Distribution rate filing, RP-2005-0020/EB-2005-0378. This methodology allocates the costs of shared services OM&A among Hydro One’s subsidiary companies, including Remotes.

Depreciation and amortization expense of $4,469 thousand for 2009 has been determined based on the results of Remotes’ depreciation policy. These costs are described in written evidence at Exhibit C1, Tab 4, Schedule 1 and shown in detail in C2, Tab 5, Schedule 1.

Depreciation was calculated using the Depreciation Study methodology submitted and approved as part of Hydro One Networks' 2006 Distribution rate filing (RP-2005-0020/EB-2005-0378) which Remotes has adapted.

Remotes has calculated working capital based on the formula-based methodology described in the Board's Filing Guidelines for Transmitters and Distributors. The calculation of working capital, filed at Exhibit D2, Tab 4, Schedule 1, incorporates generation-related OM&A accounts as Remotes provides integrated generation and distribution services.

Remotes' proposed Rate Base of $30,326 thousand is discussed at Exhibit D1, Tab 1, Schedule 1.

Remotes is 100% debt-financed, consisting of 4% deemed short-term debt and 96% long-term debt. Remotes' evidence in support of its cost of capital appears at Exhibit B1, Tab 1, Schedule 1.

Under the terms of the Electrification Agreements, INAC is responsible for funding generation capital upgrades and service connections associated with load growth in the First Nations Communities served by Remotes. Remotes is responsible for funding capital replacements, and for capital improvements not associated with load growth. This submission reflects the costs net of expected capital contributions from INAC, for Remotes' plan to invest in generation and distribution assets to meet its objectives regarding public and employee safety; environmental responsibility; regulatory and legislative compliance; and service quality and reliability. The capital project and program approval and control policy is presented at Exhibit A, Tab 13, Schedule 3. Remotes is forecasting total capital expenditures of $5,138 thousand, net of contributed capital. Details of Remotes’ capital budget are illustrated in schedules filed at Exhibit D2, Tab 2 and discussed in detail at Exhibit D1, Tab 3.

In 2007, RRRP transfers accounted for 62% of Remotes revenues. Rural and Remote Rate Protection for customers in Remotes' service area is currently set at $21,097 thousand per year. Remotes is requesting to increase RRRP revenue subsidies to $27,845 thousand, or 66% of 2009 Test Year revenues.

Remotes earns less than 1% of its revenues from sources other than its distribution tariff or RRRP. The costs incurred to generate these revenues are included in Remotes’ cost of service. External revenues of $103 thousand in 2009 are recorded as revenue with an offset expense recorded in OM&A. External revenues are discussed at Exhibit E3, Tab 1, Schedule 1.

In accordance with standard regulatory practice, Remotes has incurred prior costs for which it is requesting approval in this submission. A total of $4,013 thousand is forecast to be recorded at December 31, 2008 in the Rural and Remote Rate Protection Variance Account, primarily related to increased diesel fuel costs. Remotes is proposing to recover the $4,013 thousand in the 2009 test year resulting in a RRRP amount of $31,858 thousand. Remotes’ submission regarding this account balance and proposed disposition appears at Exhibit F1, Tab 1, Schedule 1.

Remotes recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. This regulatory asset is amortized consistent with the actual expenditures incurred each year. Remotes forecasts assessment and remediation costs of $1,500 thousand in the 2009 Test Year. Land Assessment and Remediation is discussed in Exhibit C1, Tab 2, Schedule 2, Appendix A.

SUMMARY OF REMOTES BUSINESS

1.0 INTRODUCTION

Remotes is an integrated generation and distribution company licensed to generate and distribute electricity within 20 isolated communities in northern Ontario (ED 2003-0037 and EG-2003-0138). A list of the communities served and a map of Remotes' distribution service territory can be found in Exhibit A, Tab 7, Schedule 1. Remotes is 100% debt-financed and operates as a break-even business.

Remotes is driven by its corporate vision, mission and business values. Together, they provide the basis to deliver on targeted performance objectives.

1.1 Corporate Vision

"We will be the **BEST** off-grid utility measured against performance in Safety, Environment and Customer Loyalty."

1.2 Corporate Mission

"We are an off-grid electrical generation and distribution company focused on **customer satisfaction** and utilizing management systems to achieve **operational excellence**."

1.3 Corporate Values

We value:

- Customers
- Safe work environment
- Environmental responsibility
- Consistent, fair, treatment of customers and staff
- Financial responsibility and accountability
- Business integrity
- Employee development & recognition
- Employee involvement in business and understanding of business drivers
- Continuous improvement

2.0 REMOTES' BUSINESS ENVIRONMENT

Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, and logistical challenges related to transportation, along with the absence of an integrated transmission system and complex funding arrangements with third parties, set Remotes apart from other Ontario electricity distributors. This unique operating environment has a profound impact on operations and costs throughout Remotes' service area.

Remotes inherited obligations that were entered into in the 1970s and 1980s under arrangements with the provincial and federal governments. Both levels of government had programs and policies to encourage northern electrification within communities that requested Ontario Hydro to take over electrical operation of the communities. The federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government, through

Indian and Northern Affairs Canada ("INAC"), remain in place. These Agreements specify that Remotes is responsible for funding ongoing operation and maintenance of the system and that INAC is responsible for funding capital related to system expansions and capital upgrades. Remotes' revenue requirement does not include funding for these capital projects, and Remotes does not depreciate this contributed capital.

During the 1990s, INAC devolved its responsibility for community infrastructure to First Nation communities. INAC now transfers funding directly to First Nations, who are responsible for administering approximately 85 percent of the Department's program funds. As a result of these funding arrangements, the process for capital upgrades is complex and not completely within Remotes' control. INAC has limited capital resources and INAC or local First Nations may direct capital funding to other community infrastructure priorities. If planned upgrades are delayed due to competing capital priorities, Remotes' operating and maintenance expenses can increase.

The communities served by Remotes are isolated and are scattered across the far north of the Province. Twelve communities are not accessible by year-round road and can be accessed only by aircraft, winter road or, in the case of one community, by barge. The size and isolation of Remotes' service territory also means that the transportation and accommodation of staff, fuel, and equipment is a key driver of Remotes' costs. The use and viability of winter roads to reach these communities is a major cost variable within Remotes' operations. If a winter road cannot be built in a given year, fuel costs, equipment costs and overall maintenance costs increase.

3.0 DISTRIBUTION

Remotes operates 18 isolated distribution systems to serve the 20 communities. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. Because the communities are far from each other, the distribution systems are isolated, distinct and stand-alone. These distribution systems operate at distribution voltages ranging from 4.8 kV to 25 kV.

The fixed distribution assets in service include approximately 210 kilometers of line and transformers distributed throughout the system, which are used for voltage transformation. Billing meters are used to measure energy consumption at customer supply points.

4.0 GENERATION

Due to the lack of grid connection, Remotes is a generator of electricity to meet its obligations under section 29 of the *Electricity Act, 1998*. Diesel generation is currently the prime source of electricity within the communities. Remotes also owns and operates two run-of-the-river mini-hydro electric generating facilities and has four demonstration project windmills. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost-effective technology.

There are presently 55 diesel generators in service, ranging in size from 85kW to 1100kW. Most stations have three generators, sized to meet community load at different times of the day. Automated operation ensures that the generation units are run to maximize fuel efficiency by matching the generator size to the community load. Depending on electrical demand, Remotes handles 14 to 17 million litres of diesel fuel each year.

5.0 ENVIRONMENTAL MANAGEMENT SYSTEM

Remotes developed an Environmental Management System ("EMS") in 1999 to help address a history of spills and to improve environmental performance. In the course of developing and implementing the EMS, Remotes has transformed itself into an environmental leader, recognized provincially and nationally for its environmental record. In 2001, Remotes was awarded the Canadian Council of Ministers of the Environment national Pollution Prevention award for small business in Canada. In 2002, Remotes achieved ISO 14001 registration of its EMS. This international registration is in addition to the significant environmental improvements achieved since implementing the EMS.

Remotes has achieved operating efficiency improvements through installation of automated Programmable Logic Controller ("PLC") controls, Supervisory Control and Data Acquisition ("SCADA") systems, upgraded engines and redesigned generating and fuel-handling software to support its PLC programs, all of which have resulted in improved efficiency, reduced use of diesel fuel and lower atmospheric emissions.

In 2003, Remotes developed and adopted an Emission Reduction Strategy and submitted an application and Action Plan for Reducing Greenhouse Gases to the Environment Canada Voluntary Challenge Registry. Remotes' 2003 report received the "Best New Submission" award; and since then, each annual submission was awarded "Gold Champion" status.

6.0 GOVERNMENT REGULATION AND REMOTE COMMUNITY RATES

Remotes served 3,332 customers at the end of 2007. Most customers within Remotes, approximately 87%, pay rates below the cost of service. Historically, rates for these

Residential and General Service customers have been financially supported through a cross-subsidy from government customers within Remotes who historically have paid rates above cost (Standard A Rates); through capital contributions; and through RRRP. RRRP funding is currently set at $21,097 thousand per year and is funded through a $0.001/kWh charge to all grid-connected customers in Ontario.

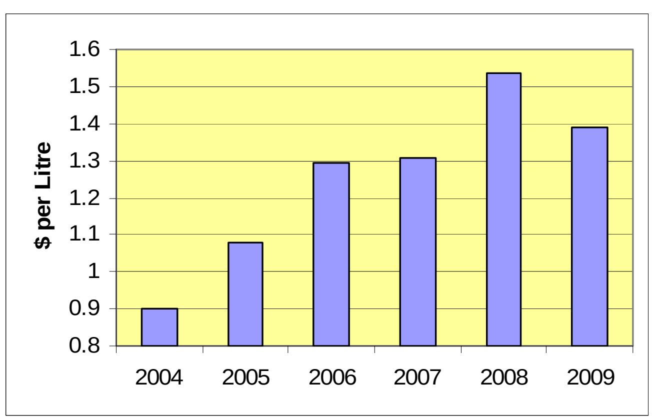
O. Reg 442/01, the provincial regulation under the *Ontario Energy Board Act*, *1998*, that also established RRRP, sets out two broad categories of customers in Remotes:

- Customers who receive Rural and Remote Rate Protection ("Residential and General Service" customers); and
- Customers occupying Government premises, defined as customers who receive direct or indirect funding from government ("Standard A" customers).

Rates for Remotes' customers are shown in Exhibit G1, Tab 1, Schedule 1.

7.0 CHALLENGES AND OPPORTUNITIES FACING REMOTES

Since Remotes' last rate application three years ago, major changes have occurred that affect Remotes' operations. Most notably, diesel fuel prices have increased markedly. The graph below shows increases in the delivered price of a litre of diesel fuel.



The cost for diesel fuel used in Remotes' electrical generation includes the cost of delivery. Through the use of winter roads and the implementation of improved supplier contracts for delivery, Remotes has been able to moderate increases in the delivered price of fuel compared to increases in commodity prices. The delivered cost of diesel fuel has increased by 70% since 2004 compared to the costs in 2008. World fuel prices have moderated recently, and fuel prices are expected to decrease in 2009 compared to 2008. However, prices are still anticipated to be more than 50% higher in 2009 than in 2004.

These increases have created major cost pressures, as diesel generation is the prime source of electricity in Remotes' service territory, and because higher fuel prices also increase the cost to transport staff, materials, equipment and fuel itself.

Remotes continues to investigate renewable energy technology opportunities and is working with local First Nations and external parties to develop renewable energy sources in its service territory.

Remotes is also managing challenges related to ongoing inflation, increased safety and environmental regulation, and industry wide shortages of skilled workers, in particular, skilled trades staff.

In response to these cost pressures, Remotes has improved the coordination of flights to transfer staff and equipment, improved its use of winter roads, introduced a customer Conservation Demand Management ("CDM") program, and developed new standards for station efficiency. Our conservation program saved 300,000 litres of fuel in 2007. Efficiency improvements to our stations are expected to reduce diesel usage by 4% per kWh generated.

NOTICES OF MOTION

To be filed behind this tab as and when Notices are filed.

COMPLIANCE WITH LICENCE AND OEB FILING REQUIREMENTS FOR ELECTRICITY DISTRIBUTORS

1.0 INTRODUCTION

This application by Remotes is substantially consistent with the requirements of the 2006 Electricity Distribution Rate Handbook ("the Handbook") issued by the Board on May 11, 2005 and with the Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements") issued by the Board on November 14, 2006.

1.1 Compliance with Licence

<u>Exemptions from the *Electricity Act, 1998*</u>

Remotes is exempt from the following sections of the *Electricity Act, 1998*:

- Subsection 26(1), non-discriminatory access
- Subsection 26(3), to the extent that a contract entered into by Ontario Hydro contains liabilities, rights or obligations that have been transferred to Remotes
- Section 28, distributor's obligation to connect.

<u>Exemptions from the *Ontario Energy Board Act, 1998*</u>

Remotes is exempt from the following sections of the *Ontario Energy Board Act, 1998*:

- Section 70(2)(e), specifying methods or techniques to be applied in determining the licensee's rates
- Section 71, restriction on business activity
- Section 79.1, payments to consumers
- Section 79.2 payments by IESO to consumers

- Section 80, prohibition, generation by transmitters or distributors
- Section 81, prohibition, transmission or distribution by generators

None of Remotes' customers are prescribed under Sections 78(3.1) or 79.16 under the *Ontario Energy Board Act, 1998*.

Exemptions from Licence Conditions

Remotes is exempt from the entire Standard Supply Service Code and the entire Retail Settlement Code, per Schedule 3 of its Distribution Licence ED-2003-0037 filed at Exhibit A, Tab 6, Schedule 1, Attachment 1.

2.0 COMPLIANCE WITH ELECTRICITY DISTRIBUTOR FILING GUIDELINES

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the Ontario Energy Board Act, 1998. O. Reg. 442/01 under that statute requires the Board to calculate Rate Protection for these customers. This legislation requires that Remotes charge rates that are not based on the cost of service. In view of this legislative requirement, Remotes did not undertake a cost allocation study as required by Board guidelines prior to filing this application. A cost allocation study requires substantial effort and would have provided no benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation.

Remotes provides both generation and distribution services outside of the competitive market. Its rates and revenue requirement include both of these cost categories. Accordingly, information on all of Remotes' activities are included to ensure that generation and distribution costs can be examined in this proceeding.

The filing requirements indicate that a forward test-year methodology is to be utilized when a distributor is seeking the Board's approval for rebasing its rates. Remotes' application has been filed using a forward test year and provides three years of historical data. As such, this Application includes written evidence and supporting schedules for the following:

- 2009 test year;
- 2008 bridge year;
- 2005, 2006 and 2007 historical years;
- 2006 Board-approved historical year.

Remotes 2009 Revenue Requirement reflects the adoption of the amortization rates approved by the Board in Hydro One Distribution's EB-2005-0378 filing, based on the depreciation study by Foster Associates accepted by the Board in that proceeding.

Remotes' calculation for working capital is consistent with the formula described in the 2006 Electricity Distribution Rate Handbook.

The interest rate used for construction work in progress (CWIP), also referred to as Allowance for Funds Used During Construction (AFUDC), reflects the Board's decision in EB-2006-0017, effective November 28, 2006. This decision prescribed that the interest rate to use for CWIP would be the Scotia Capital All-Corporate Mid-Term Yield, as published on the Bank of Canada website and updated quarterly. As a result, 2007, 2008 bridge and 2009 test years reflect the prescribed CWIP rate on a forecast basis, while 2005 and 2006 historical years reflect CWIP at Remotes' previously approved embedded cost of debt.

Details for all capital projects and programs that exceed $230 thousand in net capital costs (1% of 2007 Net Fixed Assets) are provided in Investment Justification Documents

(IJDs). The IJDs for these projects and programs are filed at Exhibit D2, Tab 2, Schedule 3.

Remotes continues to plan, manage and perform its internal and external reporting on a work basis using its general ledger accounts, as these are reflective of the way in which Remotes' manages its operations. A schedule showing in-service additions by OEB-specified USofA accounts for 2009 year, 2008 bridge year and 2007 historical year is filed in Exhibit D2, Tab 2, Schedule 4.

Remotes cost of capital is 100% debt-financed, consistent with the Board's Decision in RP-1999-001. As Remotes operates as a break-even company, it does not plan to seek a return on equity.

Remotes OM&A evidence has been filed on a USofA basis. Information for the 2009 test year, 2008 bridge year and 2007 historical year is filed at Exhibit C2, Tab 2, Schedule 1.

3.0 COMPLIANCE WITH BOARD DIRECTIVES

Item #	Docket Number	Issue	Directive	Response
(i)	RP-2005-0020/EB-2005/0497	TRC Testing Results	Complete and file the full TRC testing results for the Conservation and Demand Management program.	Filed August 4, 2006
(ii)	RP-2005-0020/EB-2005/0497	Smart Meter Feasibility	File a report on the feasibility of smart meters in Remotes' service territory and plans for smart metering	Filed August 4, 2006

DISTRIBUTION AND GENERATION LICENCE

The Ontario Energy Board Act requires any entity that distributes electricity to obtain a Distribution licence and any entity that generates electricity to obtain a Generation license. The Hydro One Remote Communities Inc.'s distribution licence (Attachment A) and generation license (Attachment B) are filed as attachments to this exhibit. The licences identify Remotes' service territory and generation facilities, and address various obligations, such as the obligation to comply with codes, legislation, regulation and market rules and to maintain system integrity.

The Company confirms that, as with all its licences, its Distribution and Generation licences are being complied with in all material respects and are in good standing.

Electricity Distribution Licence

ED-2003-0037

Hydro One Remote Communities Inc.

Valid Until
December 23, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: December 24, 2003

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions 1

In this Licence: 2

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee; 3

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 4

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; 5

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order; 6

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems; 7

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A; 8

"**Licensee**" means: Hydro One Remote Communities Inc.; 9

"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act; 11

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 12

"**regulation**" means a regulation made under the Act or the Electricity Act; 13

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers; 14

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act; 15

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 16

2 Interpretation 17

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 18

3 Authorization 19

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence: 20

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; and 21

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence. 22

4 Obligation to Comply with Legislation, Regulations and Market Rules 23

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation. 24

4.2 The Licensee shall comply with all applicable Market Rules. 25

5 Obligation to Comply with Codes 26

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence: 27

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 28

b) the Distribution System Code; 29

5.2 The Licensee shall: 30

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and 31

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 32

6 Obligation to Sell Electricity 33

6.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Licensee's Rate Order as approved by the Board. 34

7 Obligation to Maintain System Integrity 35

7.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board. 36

8 Market Power Mitigation Rebates 37

8.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 38

9 Distribution Rates 39

9.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board. 40

10 Separation of Business Activities 41

10.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board. 42

11 Expansion of Distribution System 43

11.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 44

11.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine. 45

12 Provision of Information to the Board 46

12.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time. 47

12.2 Without limiting the generality of condition 12.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs. 48

13 Restrictions on Provision of Information 49

13.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. 50

13.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed: 51

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 52

b) for billing, settlement or market operations purposes; 53

c) for law enforcement purposes; or 54

d) to a debt collection, board council or government agency for the processing of past due 55
accounts of the consumer or generator.

13.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators 56
where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

13.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under 57
which their information may be released to a third party without their consent.

13.5 If the Licensee discloses information under this section, the Licensee shall ensure that the informa- 58
tion provided will not be used for any other purpose except the purpose for which it was disclosed.

14 Customer Complaint and Dispute Resolution 59

14.1 The Licensee shall: 60

a) have a process for resolving disputes with customers that deals with disputes in a fair, 61
reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute 62
resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the 63
public at each of the Licensee’s premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; 64
and

e) subscribe to and refer unresolved complaints to an independent third party complaints 65
resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

15 Term of Licence 66

15.1 This Licence shall take effect on December 24, 2003 and expire on December 23, 2023. The term 67
of this Licence may be extended by the Board.

16 Fees and Assessments 68

16.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 69

17 Communication 70

17.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change. 71

17.2 All official communication relating to this Licence shall be in writing. 72

17.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 73

a) when delivered in person to the addressee by hand, by registered mail or by courier; 74

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 75

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 76

18 Copies of the Licence 77

18.1 The Licensee shall: 78

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and 79

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 80

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 81

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence. 82

1. Armstrong 83
2. Attawapiskat 84
3. Bearskin Lake 85
4. Big Trout Lake 86
5. Biscotasing 87
6. Collins 88
7. Deer Lake 89
8. Fort Severn 90
9. Gull Bay 91
10. Hillsport 92
11. Kasabonika Lake 93
12. Kingfisher Lake 94
13. Landsdowne House 95
14. Oba 96
15. Sachigo Lake 97
16. Sandy Lake 98

17. Sultan 99

18. Wapakeka 100

19. Weagamow 101

20. Webequie 102

21. Whitesand 103

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 104

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act. 105

For the purposes of fulfilling its obligation under section 29 of the Electricity Act the Licensee is authorized to retail electricity directly to consumers. 106

SCHEDULE 3 LIST OF CODE EXEMPTIONS 107

This Schedule specifies any specific Code requirements that are not applicable to the Licensee. 108

1. The entire Retail Settlement Code 109

2. The entire Standard Supply Service Code 110

APPENDIX A MARKET POWER MITIGATION REBATES 111

1 Definitions and Interpretation 112

In this Licence, 113

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 114

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates; 115

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 116

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 117

2 Information Given to IMO 118

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 119

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 120

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 121

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to: 122

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 123

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 124

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 125

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment. 126

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period. 127

3 Pass Through of Rebate 128

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 129

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented; 130

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 131

c embedded distributors to whom the distributor distributes electricity. 132

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor. 133

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement: 134

"ONTARIO POWER GENERATION INC. rebate" 135

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 136

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 137

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 138

Ontario

Electricity Generation Licence

EG-2003-0138

Hydro One Remote Communities Inc.

Valid Until
October 19, 2023

____

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 20, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4

1 Definitions 1

In this Licence: 2

> "**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 3
>
> "**Electricity Act**" means the *Electricity Act, 1998,* S.O. 1998, c. 15, Schedule A; 4
>
> "**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose; 5
>
> "**Licensee**" means: Hydro One Remote Communities Inc.; 6
>
> "**regulation**" means a regulation made under the Act or the Electricity Act; 7

2 Interpretation 8

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 9

3 Authorization 10

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in the Licence: 11

a) to generate electricity or provide ancillary services for sale through the IMO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1; 12

b) to purchase electricity or ancillary services in the IMO-administered markets or directly from a generator subject to the conditions set out in this Licence; and 13

c) to sell electricity or ancillary services through the IMO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence. 14

4 Obligation to Comply with Legislation, Regulations and Market Rules 15

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation. 16

4.2 The Licensee shall comply with all applicable Market Rules. 17

5 Obligation to Maintain System Integrity 18

5.1 Where the IMO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IMO-controlled grid, for the Licensee to provide energy or ancillary services, the IMO may require the Licensee to enter into an agreement for the supply of energy or such services. 19

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board. 20

6 Restrictions on Certain Business Activities 21

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act. 22

7 Provision of Information to the Board 23

7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time. 24

7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs. 25

8 Term of Licence 26

8.1 This Licence is effective on October 20, 2003 and shall expire on October 19, 2023. The term of this Licence may be extended by the Board. 27

9 Fees and Assessment 28

9.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 29

10 Communication 30

10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change. 31

10.2 All official communication relating to this Licence shall be in writing. 32

10.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 33

a) when delivered in person to the addressee by hand, by registered mail or by courier; 34

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 35

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 36

11 Copies of the Licence 37

11.1 The Licensee shall: 38

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and 39

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 40

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES 41

The Licence authorizes the Licensee only in respect to the following: 42

1. Armstrong Generation Station, owned and operated by the Licensee at Armstrong, Ontario. 43

2. Attawapiskat Generation Station, owned and operated by the Licensee at Attawapiskat, Ontario. 44

3. Bearskin Lake Generation Station, owned and operated by the Licensee at Bearskin Lake, Ontario. 45

4. Big Trout Lake Generation Station, owned and operated by the Licensee at Big Trout Lake, Ontario. 46

5. Biscotasing Generation Station, owned and operated by the Licensee at Biscotasing, Ontario. 47

6. Dear Lake Generation Station, owned and operated by the Licensee at Dear Lake, Ontario. 48

7. Fort Severn Generation Station, owned and operated by the Licensee at Fort Severn, Ontario. 49

8. Gull Bay Generation Station, owned and operated by the Licensee at Gull Bay, Ontario. 50

9. Hillsport Generation Station, owned and operated by the Licensee at Hillsport, Ontario. 51

10. Kasabonika Generation Station, owned and operated by the Licensee at Kasabonika Lake, Ontario. 52

11. Kingfisher Lake Generation Station, owned and operated by the Licensee at Kingfisher Lake, Ontario. 53

12. Lansdowne House Generation Station, owned and operated by the Licensee at Lansdowne House, Ontario. 54

13. Oba Generation Station, owned and operated by the Licensee at Oba, Ontario. 55

14. Sachigo Lake Generation Station, owned and operated by the Licensee at Sachigo Lake, Ontario. 56

15. Sandy Lake Generation Station, owned and operated by the Licensee at Sandy Lake, Ontario. 57

16. Sultan Generation Station, owned and operated by the Licensee at Sultan, Ontario. 58

17. Wapekeka Generation Station, owned and operated by the Licensee at Wapekeka, Ontario. 59

18. Weagamow Lake Generation Station, owned and operated by the Licensee at Weagamow Lake, Ontario. 60

19. Webequie Generation Station, owned and operated by the Licensee at Webequie, Ontario. 61

20. Deer Lake Mini Hydel Generation Station, owned and operated by the Licensee at Deer Lake, Ontario. 62

21. Sultan Hydel Generation Station, owned and operated by the Licensee at Sultan, Ontario. 63

MINISTER’S LETTER TO MARTEN FALLS

RECEIVED JUL 0 8 2005

Minister of Energy

Hearst Block, 4th Floor
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6715
Fax: 416-327-6754

Ministre de l'Énergie

Édifice Hearst, 4e étage
900, rue Bay
Toronto ON M7A 2E1
Tél.: 416-327-6715
Téléc.: 416-327-6754

Ontario

JUL - 4 2005

Chief Elijah K. Moonias
Marten Falls Indian Reserve #65
Ogoki Post, Ontario
P0T 2L0

Dear Chief Moonias:

Thank you for your letter enclosing a copy of Band Council Resolution #2005-06-06 regarding the provision of Rural and Remote Rate Protection to electricity customers in Marten Falls if, and when, a transfer of responsibility for the distribution of electricity in Marten Falls passes from the First Nation to Hydro One.

I have asked ministry officials to keep this request on file and to bring it forward for consideration as soon as Indian and Northern Affairs Canada (INAC), Marten Falls First Nation and Hydro One Remote Communities Inc. (RemoteCo) enter into an Electrification Agreement.

You will recall that when I wrote to you in May 2004, I advised you that such an agreement is an essential prerequisite to any transfer of responsibility from Marten Falls to Hydro One because it would deal with INAC capital funding support, land and access rights, the purchase price and condition assessment of existing electricity generation and distribution assets in the community, as well as a commitment to standard 'A' rates.

I understand that discussions between INAC, the First Nation and RemoteCo are still underway. Again, I encourage you to continue to press INAC to enter into the necessary agreements with Hydro One at the earliest opportunity.

.../cont'd

I hope this information is helpful. Once again, thank you for taking the time to write.

Sincerely,

Dwight Duncan
Minister

c: The Honourable Dalton McGuinty, Premier
Jan Carr, CEO, Ontario Power Authority
Linda Churchley, Strategic Direction and Policy Officer
Indian and Northern Affairs Canada

SERVICE AREA MAP

The attached map is a representation of Hydro One Remote's service territory. It is not a substitute for the written description in the licence. Remotes' is licensed to serve 20 communities in Ontario. The generating station in Armstrong also serves the Whitesands Reserve and the settlement of Collins through a single distribution system and generation station.

Communities Served by Hydro One Remote Communities Inc.

Armstrong
Bearskin Lake
Big Trout Lake
Biscotasing
Collins
Deer Lake
Fort Severn
Gull Bay
Hillsport
Kasabonika Lake
Kingfisher Lake
Landsdowne House
Oba
Sachigo Lake
Sandy Lake
Sultan
Wapakeka
Weagamow
Webequie
Whitesand

MAP OF REMOTES' SERVICE TERRITORY

The communities of Whitesands and Collins are served through the Armstrong Distribution System.

CORPORATE ORGANIZATION CHARTS

1.0 INTRODUCTION

This schedule describes the current organization of Remotes' business, beginning with an overview of the parent company (Hydro One Inc.), a discussion about Hydro One's subsidiary businesses, and a brief summary of Remote's affiliates and related parties transactions.

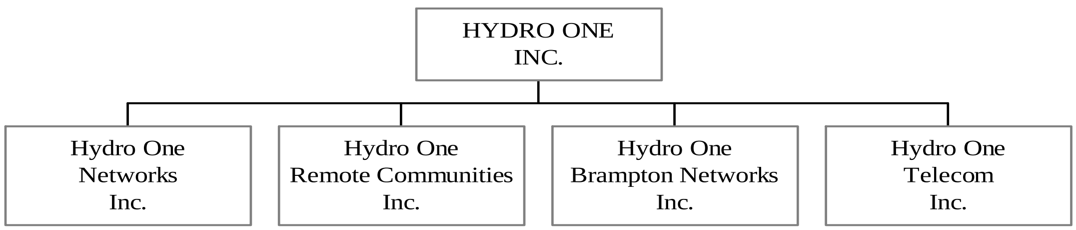
2.0 A BRIEF OVERVIEW OF HYDRO ONE INC.

Following the enactment of the *Electricity Act, 1998* and the anticipated restructuring of the former Ontario Hydro, Hydro One Inc. was incorporated under Ontario's *Business Corporations Act* on December 1, 1998 as Ontario Hydro Services Company Inc. and commenced carrying on business on May 1, 1999. On May 1, 2000, the company's name was changed to Hydro One Inc. In accordance with Section 48.1 of the *Electricity Act, 1998*, as amended, Hydro One Inc. is a holding company operating through its subsidiaries. Its principal subsidiary, Hydro One Networks Inc. (Hydro One) is the largest electricity transmitter and distributor to customers within Ontario.

Figure 1 below shows Hydro One Inc.'s principal subsidiaries, all of which are wholly-owned subsidiaries incorporated under Ontario's *Business Corporations Act*. The business functions of Hydro One and its subsidiaries are discussed in sections 3.0 and 5.0 of this Exhibit, respectively.

Figure 1

Hydro One Inc.



3.0 DESCRIPTION OF HYDRO ONE SUBSIDIARY BUSINESS ACTIVITIES

Hydro One Networks Inc. is the largest subsidiary of Hydro One. It is licenced by the Board (ET-2003-0035) to manage, own, operate and maintain Ontario’s largest transmission network. It also holds a separate licence (ED-2003-0043) to manage, own, operate and maintain a distribution network in Ontario.

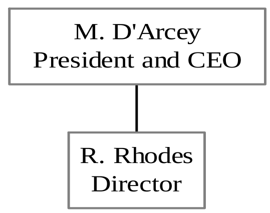
Hydro One Remote Communities Inc. carries on all business relating to ownership, operation, maintenance and construction of generation and distribution assets used in the supply of electricity to remote communities throughout northern Ontario that are not connected to the transmission grid, , and is licensed by the Board (ED-2003-0037 and EB-2003-0138).

Hydro One Brampton Networks Inc. carries on all business relating to the ownership, operation and management of distribution electricity systems and facilities in Brampton, Ontario, and is licensed by the Board (ED-2003-0038).

Hydro One Telecom Inc. carries on all business relating to leasing dark fibre and providing lit fibre capacity to other telecommunications carriers, large corporations, government, health care and education institutions.

Figure 2

Hydro One Remote Communities Inc. Organizational Chart



4.0 AFFILIATES AND RELATED PARTIES

4.1 Related Parties

Ontario Electricity Financial Corporation ("OEFC"), the Independent Electricity System Operator (the "IESO"), the Ontario Power Authority (the "OPA") and Ontario Power Generation Inc. ("OPG") are related parties of Remotes, due to their ownership by the Province. Each is described below.

a) OEFC is the financial successor corporation of Ontario Hydro, established under Section 54 of the *Electricity Act, 1998*. Among its primary responsibilities is the management and retirement of Ontario Hydro's outstanding debt and other financial obligations.
b) The IESO is the centralized independent electricity system operator responsible for maintaining the security and reliability of electricity supply in Ontario and for directing the operations of the IESO-controlled grid. The Ontario Energy Board approves the licence, business plan and fees of the IESO.
c) The OPA is mandated to ensure the adequacy and efficiency of electricity supply in the Province through planning of electricity supply and demand.

d) OPG's principal business is the generation and sale of electricity to customers in Ontario and in inter-connected markets. OPG is licensed by the Ontario Energy Board.

Transactions between these parties and Remotes are as follows:
The IESO collects customer revenues which include RRRP monies for customers in Remotes' service territory.

The provision for payments in lieu of corporate income taxes is paid to OEFC. These payments were 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.

HYDRO ONE GOVERNANCE FRAMEWORK

1.0 OVERVIEW

The corporate governance structure and Internal Control Framework of Hydro One Inc. provide reasonable assurance regarding Remote's effective and efficient operations, reliable financial reporting and compliance with applicable laws and regulations. In the past few years, federal and provincial governments and regulators have moved decisively to increase the robustness and transparency of corporate governance, as well as expand the requirements for internal control and disclosure. Although the majority of Remotes' practices already conform to these requirements, special projects have been undertaken to ensure full compliance. Tests of operational effectiveness will continue each year.

2.0 CORPORATE GOVERNANCE

Corporate governance is the mechanism by which a corporation ensures independent oversight of management activities on behalf of the shareholder(s). For Hydro One Inc., the Board of Directors and its associated committees fulfill this role, and provide direction to management through precepts such as ethical management (as established through our Code of Business Conduct), review and/or approval of a stated mission, goals and business objectives, organizational authorities, and business plans.

The company's corporate governance structure is illustrated in Figure 1. Hydro One's Board and Senior Management committees are also described in detail below.

Hydro One Corporate Governance

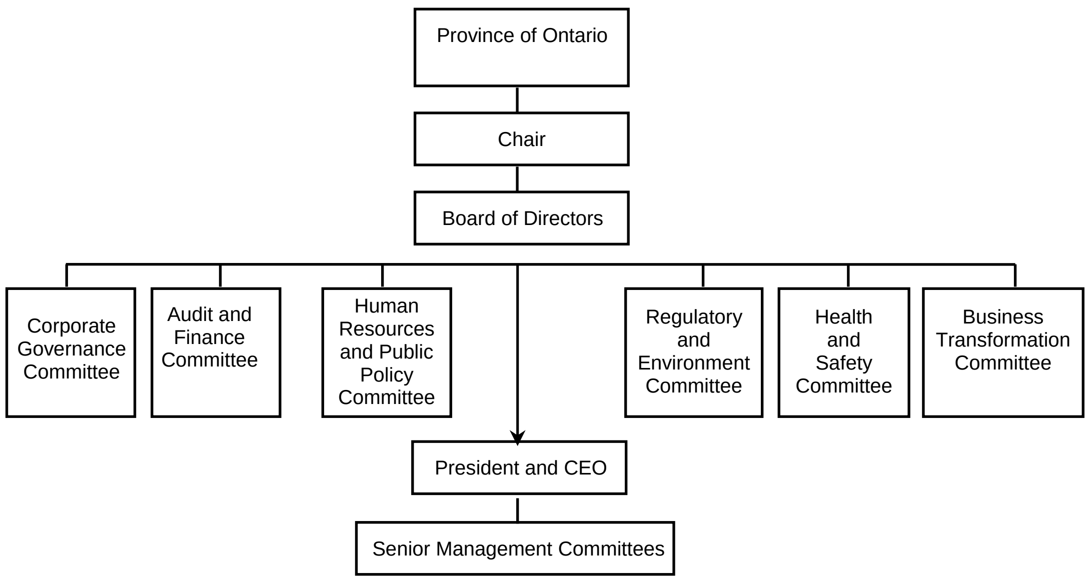


Figure 1

2.1 The Corporate Governance Committee is the Board governance committee of Hydro One Inc. and its subsidiaries. The committee is primarily responsible for carrying out an annual review of the mandates of the Board and each committee of the Board or subsidiary Boards. Other obligations include recommending issues for discussion at Board meetings, monitoring the quality of management's relationship with the Board, recommending suitable nominees to the Board of Directors, conducting the annual Board and individual director effectiveness evaluations and reviewing all director compensation.

2.2 The Audit and Finance Committee is mainly responsible for overseeing the accounting, financial reporting and auditing practices for Hydro One Inc. and its subsidiaries. Specifically, the committee makes recommendations regarding financial objectives and plans, and risk management strategies of the company. It is also accountable for reviewing and recommending to the Board for approval the interim and annual consolidated financial statements, management discussion and analysis disclosures, and financial statements in debt securities offering documents. In addition, the Audit and Finance Committee reviews the internal audit procedures of the company and advises the Board on its auditing practices and procedures, selects and oversees the work of external auditors and obtains assurance that internal controls are adequate. The committee also reviews, at least annually but more frequently if necessary, complaints brought forward under the Code of Business Conduct that relate specifically to inappropriate accounting, internal control or auditing matters. All members of the committee are independent and financially literate as per applicable Canadian securities legislation.

2.3 The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of current and future organization structures, succession plans for corporate and divisional officers, the appropriateness of the Code of Business Conduct (including any breaches for the preceding year), and the performance and remuneration of senior executives. Also, the committee identifies, assesses and provides advice to the Board on public affairs issues that have significant impact on the company.

2.4 The Regulatory and Environment Committee maintains an up-to-date understanding of regulatory and environmental compliance risks and seeks to ensure that management is effectively managing those risks. The committee is also responsible for reviewing management's regulatory strategy and proposals for transmission and distribution rate applications, as well as the status of outstanding applications. It also plays an advisory role with respect to changes or additions to environmental policies, standards, accountabilities and programs, and recommends such to the Board for approval.

2.5 The Health and Safety Committee is responsible for reviewing and ensuring compliance with occupational health and safety legislation, policies, standards, and programs. They annually review the company's state of readiness to respond to crisis situations, as well as reports of any occupational accidents. They may also review such other health and safety matters, including public health and safety, as appropriate.

2.6 The Business Transformation Committee is responsible for assisting the Board of Directors in its oversight responsibility on matters related to the Enterprise Application Systems Replacement Strategy. The strategy addresses the replacement of existing customized business applications with commercially available software system applications to simplify the information technology infrastructure and improve functionality in business processes.

3.0 HYDRO ONE SENIOR MANAGEMENT COMMITTEES

Prudent decision-making, operational effectiveness and business transparency are supported by four key senior management committees: Executive Committee, Operations Committee, Pension Committee and Disclosure Committee.

3.1 Executive Committee

This committee is a decision-making body established to review and approve business plans and strategies, capital projects and investments, key operating decisions, regulatory filings, labour strategy, financial and operational performance indicators and other items as required. The Executive Committee also reviews all project approvals prior to going to the Board.

3.2 Operations Committee

This committee provides business coordination between lines of business, including resourcing strategy, alignment of business plans, health and safety policy, support for regulatory filings and implementation of corporate strategies. They also review and coordinate operational issues and review project and program expenditures. Any required changes to project or program schedules are coordinated across all lines of business.

3.3 Pension Committee

The Pension Committee is responsible for approving appropriate pension policies, standards and programs. It is also responsible for ensuring compliance with legislation, policies and standards.

3.4 Disclosure Committee

The Disclosure Committee operates under the principle that communications to the public should be timely, factual and accurate and broadly disseminated in accordance with all applicable legal and regulatory requirements in Canada. The committee meets quarterly to review financial statements and management's discussion and analysis disclosures, offering documents for debt securities, as well as risk assessments prepared for credit rating agencies and government.

4.0 INTERNAL CONTROL FRAMEWORK

Internal controls ensure the company achieves its mission and goals, by enabling management to deal with rapidly changing economic and competitive environments, customer demands and priorities, and restructuring for future growth. Internal controls promote efficiency, reduce risk of asset loss, and help ensure the reliability of financial statements and compliance with laws and regulations.

Hydro One Inc.'s Internal Control Framework has five components, including: the Control Environment, Risk Assessment, Control Activities, Information and Communication, and Monitoring. The framework further addresses the appropriate elements of each component at the entity (Board) level, corporate (senior management) level and operational (local) level. The framework is consistent with accepted external standards and control criteria set out by such standard setting bodies as the Canadian Institute of Chartered Accountants and the US Committee of Sponsoring Organizations (COSO criteria, Internal Control-Integrated Framework). Key components of the framework are described in more detail below:

The "Control Environment" refers to direction and oversight from the top of the organization. The control environment component in the framework captures the notion of ethical and prudent financial management as established by the Board of Directors and senior management (see Section 2.0 above), and sets the tone for all financial and project management policies and practices established at lower levels. Regular education sessions on policies, processes and practices/procedures are also provided.

Hydro One Inc. has a formal Code of Business Conduct and a Disclosure Policy which have been issued to all staff, including Remotes' staff. The Code of Business Conduct requires all management employees at the director level and above to sign an annual compliance form to document that they have read, understood, and complied with the Code, and that all conflicts or potential conflicts of interest have been disclosed. The Corporate Ethics Officer ensures that this process is performed on a timely basis and that a compliance register is maintained and submitted to the President and CEO of Hydro One Inc. And lastly, individual performance contracts capture the understanding between a manager and a direct report as to the results expected and the means by which such results will be achieved.

"Risk Assessment" involves the identification and analysis by management of the key risks to achieving the company's business objectives. Remotes performs a risk assessment for all of its operations annually. This assessment provides the basis for business planning decisions. Programs that mitigate existing risks to acceptable residual levels, or provide mitigation for emerging risks, are captured in business plans. This process assesses whether any proposed solutions for a specific operational need will achieve a level of residual risk acceptable to senior management and our shareholder. Projects and programs underway are regularly assessed for new and changing risks. Moreover, at the operational level, extensive emergency and contingency plans exist and are regularly tested and updated.

"Control Activities" refers to the systems, policies and procedures that ensure management’s objectives are achieved and risk mitigation plans are carried out. Sets of policies and procedures exist to govern annual, monthly and day to day operations at the business unit and local levels. All policies have an issue date and expected review date. In many locations, policies and procedures are available through manuals and are updated on the Local Area Network. More information on Hydro One’s policies may be found in Exhibit A, Tab 11, Schedule 1.

One of the foundations of good control is the establishment of appropriate levels of authority for spending and other business decisions. The delegation and exercise of all authorities are governed by 'Guiding Principles', the Code of Business Conduct, and policies and procedures. Authorities are reviewed by the Audit and Finance Committee. Business plans, budgets and business cases establish overall spending of the company.

The budgeting and business planning process is also a critical element of effective internal controls. Annually a budget and business plan are prepared and submitted to the Board for approval. The budget and business plan sets the parameters of the company's activities for a specific fiscal period. More information on Remotes' planning process may be found in Exhibit A, Tab 13, Schedule 1.

The Executive Authority Register (EAR) delegates authorities from the Board to senior management. Remotes has an Organizational Authority Registers (OAR) that delegates authorities from senior management to Remotes' Director, Managers and Supervisors.

"Information and Communication" supports all other control components. Pertinent information must be identified, captured and communicated in a form and timeframe that enables staff to carry out their responsibilities. Regular communication occurs to all staff from the Chief Financial Officer and from the Corporate Controller with respect to new or changed policies and procedures. Presentations on various internal control matters also occur regularly. And, as noted previously, policies and procedures are printed and available in manuals in Remotes' Thunder Bay service centre. Policies and procedures are also available through the Local Area Network.

"Monitoring" covers the oversight of internal controls by management or independent parties outside the process; or the application of independent methodologies, such as customized procedures or standard checklists, by employees within a process.

Monitoring also includes assessing the quality of internal controls over time and implementing required changes.

Quarterly letters of representation and disclosure prepared and submitted by the Vice-President provides both assurance and communication with respect to internal controls and validity of financial statements. The Letter of Disclosure addresses issues such as legal claims; changes in accounting policies, practices, systems, and procedures that have occurred in the period; and financial accounting matters that could have a significant impact on financial statements. The Letter of Representation provides assurance that internal control systems, policies and procedures are in place and functioning properly and financial statements are a true representation of the business.

Every month Remotes is required to conduct a detailed review of financial results by comparing operating results to budgets and responding to discrepancies. Project details with major accounts are reconciled monthly to source sub-systems and suspense accounts are also explained and reconciled. Monthly control reports related to key aspects of operations and project activity are prepared centrally and delivered to managers for review and follow-up action as appropriate. A month-end close schedule is established to ensure timely production of financial statements. In addition, annual compliance testing of key financial activities is performed locally by Remotes' finance staff.

Compliance monitoring with respect to codes and policies is performed by multiple groups. Regulatory compliance is monitored by Regulatory Affairs (e.g. Affiliate Relationships Code; see Exhibit A, Tab 8, Schedule 3). Internal Audit performs compliance audits and uses a risk-based audit approach for prioritizing such audits. Internal controls are reviewed on a recurring cycle, again linked to level of risk. Furthermore, regular review of all outstanding items from past audits is performed. Annual year-end audits are also conducted by the external auditor.

The outsourcing contract with Inergi LP requires that Inergi conduct an independent confirmation of the integrity of financial controls for all Hydro One transactions, and allows for auditing of processes and systems by Hydro One Internal Audit. Such audits are designed to assess the appropriate occurrence, proper measurement, completeness and accuracy of transactions and whether they were classified, described and disclosed in accordance with generally accepted accounting principles.

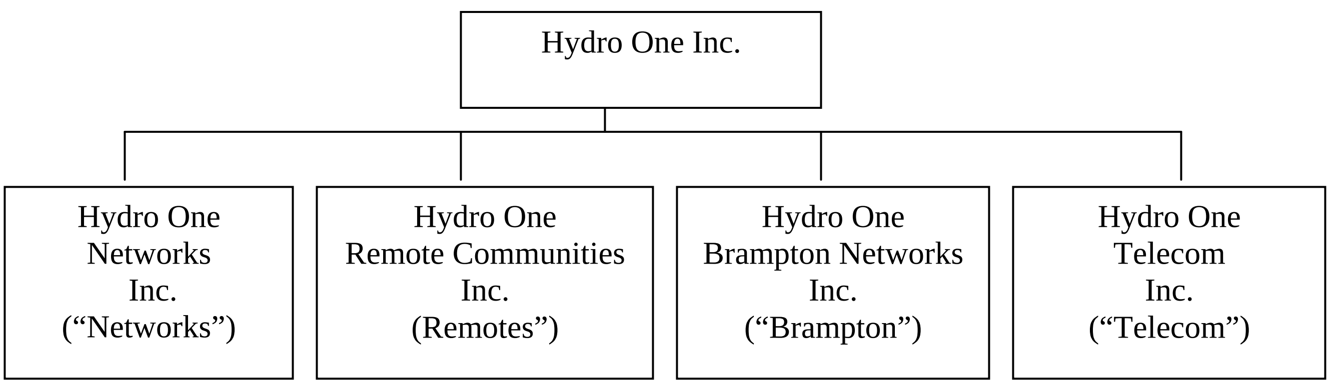
AFFILIATE SERVICE AGREEMENTS

1.0 INTRODUCTION

In accordance with the Affiliate Relationships Code ("ARC"), when Hydro One Remote Communities Inc. ("Remotes") provides services to or purchases services from affiliates, it does so in accordance with service agreements. This Exhibit discusses the current agreements between Remotes and its active affiliates. Remotes and its active affiliates are displayed originally in the corporate organization chart in Exhibit A, Tab 8, Schedule 1 and repeated in Figure 1.0 below for convenience.

Figure 1

Hydro One Inc.



2.0 THE DEVELOPMENT OF THE SERVICE AGREEMENTS

Hydro One Inc. and its affiliates identify and negotiate the nature of the services being provided or purchased, any specific terms and the prices (or, alternatively, the pricing formula) for these services. This information is incorporated into legal agreements with commercial terms and conditions, then reviewed and approved by each company's CEO or other accountable officer. Two agreements, which focus on the provision of common administrative services from Hydro One Inc. to its subsidiaries and from Networks to its affiliates, are structured as multi-party agreements and accordingly, are reviewed and signed by all parties.

The current agreements between Remotes and its service providers are listed below, in Table 1, which identifies the service provider, the recipient and a brief description of the services.

Table 1
Remotes' Service Agreements – 2008

Service Provider	***Recipient(s)***	***Description of Services***
Hydro One Inc. (Appendix A)	Networks Telecom Remotes Brampton Networks	***a) General Counsel and Secretary services*** – Professional legal advice and input as well as guidance on business ethics and support in the form of a business code of conduct. ***b) President / CEO / Chairman services*** – Strategic direction and management. ***c) Chief Financial Office services*** – Review of policies and procedures, investment decisions, treasury operations and tax planning, financial control and reporting.
Networks (Appendix B)	Hydro One Inc. Remotes Telecom Inc. Brampton Networks	***a) General Counsel and Secretary services*** – Professional legal advice and input and services regarding the protection of assets and management of security risks. ***b) Financial services*** -- Financial information, business planning, budgeting and financial reporting as well as other financial services such as treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting, decision support, transaction processing (accounts payable and receivable), and fixed asset and general accounting. ***c) Corporate services*** -- Facility management and support services, human resource services and corporate communications. ***d) Telecommunications-related services*** – Field and engineering, logistics, corporate, construction, telecommunication and information technology services. ***e) Other services*** – Supply procurement, customer services operation and information management.

Service Provider	***Recipient(s)***	***Description of Services***
Networks (Appendix C)	Remotes	***Utility Operations services*** – Provincial lines, forestry, drafting, environmental land assessment and remediation, fleet management, flight safety, training, safety, station maintenance, meter services, approval of plans, drawings and specification of installation work, joint use services and engineering and construction services.
Networks (Appendix D)	Remotes	***CEO / President services*** -- Administrative oversight, provision of strategic direction and advice and advocacy of the service recipient's position regarding operational and budgetary issues.
Remotes (Appendix E)	Networks	***Metering and Lines services*** -Lines Apprenticeship program instruction services, update, install, re-verify and sample meter changes and maintain the services recipient's distribution system.
Networks (Appendix F)	Remotes	***Joint Use services –*** implementation, training on joint use agreements and databases

3.0 TERMS AND CONDITIONS

In accordance with the ARC, the agreements describe the nature of, and the fees payable for, the services and they contain confidentiality, liability and indemnification provisions. They also describe a dispute resolution process to which the parties must adhere in resolving disputes under the agreements. More details on the key clauses are provided below.

3.1 Description of Services

The agreements address Remotes' receipt of certain common administrative and corporate services, utility operation and maintenance services and joint use services from its affiliates as well as the provision to Networks of metering and line services. The services are described in detail as a schedule to the agreements.

3.2 Fees Payable

Pursuant to the ARC, where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the market value of the service, resource or product. In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the market price. Where no fair market value is available for any product, resource or service, a utility shall charge no less than its fully-allocated cost, and shall pay no more than the affiliate's fully allocated cost.

Each services agreement specifies the price payable for the specific services described in the agreement and generally, the price is cost-based since no fair market value is available for the said services.

The annual fees payable by Remotes to its affiliates for certain common administrative and corporate services for the 2009 test year are as specified in the following table. Service agreements are provided for 2008. The amounts for 2009 are planned amounts consistent with the revenue requirements in this Application.

Table 2
Remotes' Service Agreements For 2009

FEES PAYABLE BY REMOTES FOR SERVICES TO BE RECEIVED FROM HYDRO ONE INC. AND HYDRO ONE NETWORKS ($000S)		
Services provided in affiliate agreement as described in:	**Hydro One Inc.**	**Hydro One Networks**
Appendix A		
• **2007**	54	
• **2008**	49	
• **2009**	50	
Appendix B		
• **2007**		1,085
• **2008**		1,214
• **2009**		1,469
Appendix C		
• **2007**		713
• **2008**		1215
• **2009**		983
Appendix D		
• **2007**		80
• **2008**		80
• **2009**		80
Appendix F		
• **2007**		-
• **2008**		-
• **2009**		25
Totals		
• **2007**	54	1,878
• **2008**	49	2,509
• **2009**	49	2,557

The annual fees payable to Remotes from Hydro One Networks Inc. for metering and line services are on a pay as used basis. The amounts for 2009 are planned amounts consistent with the revenue requirements in this Application.

3.3 Dispute Resolution Procedure

If the parties have a dispute under the agreement that cannot be resolved by a director or manager from each party, the dispute will be passed to the parties' respective presidents. If, after five days after receipt of notice of the dispute, the dispute is still unresolved, the matter proceeds to the President of Hydro One Inc. for final resolution.

3.4 Confidentiality

Except as required by law and in certain other circumstances (which exceptions are typical in a confidentiality agreement), each party is to maintain in strict confidence the Agreement and all information received from the other party and shall not copy or disclose the information to any third party without the prior written consent of the disclosing party. No such consent is required for disclosure to the receiving party's representatives who have a need to know. Such information includes personal information and information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator. The agreements also include security safeguards to be adhered to by the party receiving confidential information.

3.5 Intellectual Property

All rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to the service recipient by the service provider vests with the service recipient and the recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate.

3.6 Indemnification

Each party (the "indemnifying party") shall be liable for and shall indemnify the other party from and against all costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under the agreement, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of the agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages where the said losses or damages are incurred by the other party or by any third party claiming through or under the other party. The obligation to indemnify survives the termination or expiry of the agreement.

4.0 REMOTES' FINANCIAL RELATIONSHIP WITH HYDRO ONE INC.

Remotes' long-term debt was issued to the public in May 2005 by Hydro One Inc. The debt has a maturity date of May 19, 2036, and an effective cost rate of 5.60%, including issuance costs such as issue, discount, agency commissions and interest rate hedge costs.

Additionally, balances payable under the inter-company demand facility are due to Hydro One, and financing charges include interest expense on this facility.

5.0 COST-BASED PRICING

Remotes pays cost (time, materials and overheads) for utility services purchased from Hydro One Networks Inc.

Costs for shared corporate services (CF&S) are distributed according to the following principles:

1) Direct Assignment, when the portion of an activity used by a business unit can be reasonably established;
2) Allocation, when one or more business unit uses an activity, but portions of the activity cannot be directly established. In these cases, a cost driver is assigned to distribute the costs of an activity as described below.

In allocating CF&S costs, Hydro One Networks Inc. does the following:

- identifies the functions and services included in the common costs;
- identifies the activities performed to provide each of the tasks,
- determines the budgeted costs, and
- distributes the cost of each activity based on cost drivers when direct assignment is not possible.

These allocations are reviewed annually with business leaders as a test for reasonableness.

AFFILIATE SERVICE AGREEMENTS

Appendix A

Hydro One Inc.

Service Provision to:

Hydro One Networks Inc.
Hydro One Telecom Inc.
Hydro One Remote Communities Inc.
Hydro One Brampton Networks Inc.

2008

(Legal advice, financial services, strategic direction and management)

THIS AGREEMENT made in duplicate this 1st day of January, 2008 (the "Effective Date").

BETWEEN:

HYDRO ONE INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC., HYDRO ONE NETWORKS INC., HYDRO ONE TELECOM INC. and HYDRO ONE BRAMPTON NETWORKS INC.
(individually, the "Services Recipient" and collectively, the "Services Recipients")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to each of the Services Recipients by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide to each of the Services Recipients (as may be required by each of them respectively from time to time during the term of this Agreement) the following services (the "**Services**"), which Services are more particularly described in Schedule "A" attached hereto:

- General Counsel & Secretary (including Corporate Executive Office) services
- President / CEO / Chairman services
- Chief Financial Office services (including Strategic Financial services)
- Use of certain assets by Hydro One Networks Inc.

3.0 FEES PAYABLE

(a) The price for the performance of the Services for each of the Services Recipients shall be as identified in Schedule "A" attached hereto, exclusive of any sales and use taxes, as may be applicable. The relevant price for the Services shall be paid by each of the Services Recipients to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, a Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the said Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the said Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST 25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
   - (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
   - (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
   - (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) Each Services Recipient represents and warrants that:
   - (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
   - (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000" and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **<u>Safety and Security Measures</u>**: When any part of the Services is to be performed at any of the Services Recipients' premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **<u>Meetings</u>**: Each of the Services Recipient and the Services Provider shall, after the Effective Date, meet at least twice during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Freedom of Information and Protection of Privacy Act* (Ontario) and the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(iv) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

Each of the Services Recipients shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the said Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

This Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

The Services Provider shall indemnify each of the Services Recipients and the Services Recipient's respective successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Services Provider's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Each Services Recipient shall indemnify the Services Provider and the Services Provider's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the said Services Recipient's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, no party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other parties or any of them or by any third party claiming through or under the other parties or any of them.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE TELECOM INC.
65 Kelfield Street,
Rexdale, Ontario M9W 5A3

Attention:	**Cliff Truax**
Telephone:	416-240-6713
Telecopier:	416-240-6802

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Una O'Reilly**
	TCT14
Telephone:	416-345-6698
Telecopier:	416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Greg Van Dusen**
	TCT 14 C14
Telephone:	416-345-5722
Telecopier:	416-345-5401

HYDRO ONE INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Beth Summers**
	TCT15
Telephone:	416-345-4008
Telecopier:	416-345-6058

HYDRO ONE BRAMPTON NETWORKS INC.
175 Sandalwood Parkway West,
Brampton, Ontario
L7A 1E8

Attention:	**James Gribbon**
Telephone:	(905) 840-6300 ext. 205
Telecopier:	(905) 840-0967

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of any of the Services Recipients, this Agreement shall immediately terminate as between the said Services Recipient and the Services Provider only. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by any of the Services Recipients without the prior written consent of the Services Provider and by the Services Provider without the prior written consent of the affected Services Recipient, in either case which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

13.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Marchant
Title: President and CEO
I have authority to bind the corporation.

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
I have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: Secretary
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Beth Summers
Title: Chief Financial Officer
I have authority to bind the corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Roger A. Albert

Name: Roger A. Albert
Title: President and CEO
I have authority to bind the corporation.

<u>Schedule "A"</u>

The annual cost for the performance of the Services to be delivered is summarized as follows:

Services	SERVICES TO BE PROVIDED BY HYDRO ONE INC. TO: (in $Thousands)			
	Hydro One Networks Inc.	Hydro One Remote Communities Inc.	Hydro One Telecom Inc.	Hydro One Brampton Networks Inc.
General Counsel & Secretary (including Corporate Executive Office)	907	24	10	19
President / CEO / Chairman Services	3,366	18	25	36
Chief Financial Office Services (including Strategic Financial services)	804	7	28	38
Totals	5,077	49	63	93

DESCRIPTION OF SERVICES:

General Counsel and Secretary

The Services Provider shall provide the Services Recipient with professional legal advice and input. This advice shall include, but shall not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licences), contracts, and environmental and health and safety issues. The Services Provider will also provide guidance on business ethics and support in the form of a business code of conduct.

President / CEO / Chairman services

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.

Chief Financial Office services (including Strategic Financial services)

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate financial goals are achieved.

The Services Provider shall provide the Services Recipient with strategic approval with respect to investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting will also be provided by the Services Provider to the Services Recipient as required by the Services Recipient.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix B

Hydro One Networks Inc.

Service Provision to:

Hydro One Inc.
Hydro One Telecom Inc.
Hydro One Remote Communities Inc.
Hydro One Brampton Networks Inc.

2008

(General Counsel/Secretary Services, Financial services, Corporate services, telecommunications services, supply procurement, customer services operation and information management)

THIS AGREEMENT made in duplicate this 1st day of January, 2008 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC, HYDRO ONE INC.
HYDRO ONE TELECOM INC., and HYDRO ONE BRAMPTON NETWORKS INC.

(individually, the "Services Recipient" and collectively, the "Services Recipients")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to each of the Services Recipients by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide to each of the Services Recipients (as may be required by each of them respectively from time to time during the term of this Agreement) the following services (the "**Services**"), which Services are more particularly described in Schedule "A" attached hereto:

- General Counsel and Secretary services
- Financial services
- Corporate services
- Telecommunications Services
- Other services

3.0 FEES PAYABLE

(a) The price for the performance of the Services for each of the Services Recipients shall be as identified in Schedule "A" attached hereto, exclusive of any sales and use taxes, as may be applicable. The relevant price for the Services shall be paid by each of the Services Recipients to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the

Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, a Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the said Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the said Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) Each Services Recipient represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipients' premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: Each of the Services Recipient and the Services Provider shall, after the Effective Date, meet at least twice during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Freedom of Information and Protection of Privacy Act* (Ontario) and the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

Each of the Services Recipients shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the said Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

The Services Provider shall indemnify each of the Services Recipients and the Services Recipient's respective successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Services Provider's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Each Services Recipient shall indemnify the Services Provider and the Services Provider's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the said Services Recipient's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, no party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other parties or any of them or by any third party claiming through or under the other parties or any of them.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE TELECOM INC.
65 Kelfield Street,
Rexdale, Ontario M9W 5A3

Attention: **Cliff Truax**
Telephone: 416-240-6713
Telecopier: 416-240-6802

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention: **Una O'Reilly**
TCT 14
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention: **Greg Van Dusen**
TCT 14 C14
Telephone: 416-345-5722
Telecopier: 416-345-5401

HYDRO ONE INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Beth Summers**
	TCT 15
Telephone:	416-345-4008
Telecopier:	416-345-6285

HYDRO ONE BRAMPTON NETWORKS INC.
175 Sandalwood Parkway West,
Brampton, Ontario
L7A 1E8

Attention:	**James Gribbon**
Telephone:	(905) 840-6300 ext. 205
Telecopier:	(905) 840-0967

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate as between each of the Services Recipients and the Services Provider. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by any of the Services Recipients without the prior written consent of the Services Provider and by the Services Provider without the prior written consent of the affected Services Recipient, in either case which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

13.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Marchant
Title: President and CEO
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Name: Maureen Wareham
Title: Secretary
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Beth Summers
Title: Chief Financial Officer
I have authority to bind the corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Name: Roger A. Albert
Title: President and CEO
I have authority to bind the corporation.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

	SERVICES TO BE PROVIDED BY HYDRO ONE NETWORKS INC. TO: (in $Thousands)			
SERVICES	**Hydro One Inc.**	**Hydro One Remote Communities Inc.**	**Hydro One Telecom Inc.**	**Hydro One Brampton Networks Inc.**
General Counsel and Secretary Services	**75**	**220**	**75**	**150**
Financial Services	**57**	**308**	**354**	**236**
Corporate Services		**89**	**146**	**28**
Telecommunication Services		**118**	**195**	
Other Services		**479**	**1,086**	
Totals	**132**	**1,214**	**1,856**	**414**

DESCRIPTION OF SERVICES:

The following provides a generic description of all Services to be provided by the Services Provider.

GENERAL COUNSEL AND SECRETARY SERVICES

The Services Provider shall provide the Services Recipient with professional legal advice and input which shall include, but not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licenses), contracts, and environmental and health and safety issues. The Services Provider will also provide services regarding the protection of assets and management of security risks.

FINANCIAL SERVICES

The Services Provider shall provide financial services support to the Services Recipient by providing timely and reliable financial information. The Services Provider will also provide services relating to business planning, budgeting and financial reporting. As required, services relating to treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting and decision support will also be provided. Other financial services such as transaction processing (accounts payable and receivable), and fixed asset and general accounting will also be provided.

CORPORATE SERVICES

The Services Provider shall provide corporate services in three main areas:

- facility management and support services – management services related to acquisition, maintenance, protection and disposal of the Services Recipient's portfolio of land holdings as well as facilities and buildings management, including office accommodation and all related support and services; services related to the appraisal, negotiation and acquisition of real estate rights including: full ownership, easements, leases, licenses, and permits, as well as special projects.
- human resource services – provision of human resource policy, strategy and standards to meet legal and other requirements. This includes staff planning, leadership development, succession planning and change management, as well as labour relations services, pay equity, diversity, health services and performance management, compensation, health and benefits programs and administration of payroll, benefits plans and incentive programs.
- corporate communications – provision of strategy, program and support for corporate communications, public affairs and media relations, as well as corporate and shareholder relations and strategy and programs related to internal communications.

TELECOMMUNICATIONS SERVICES

The Services Provider shall provide the Services Recipient with various telecommunications-related services including field and engineering, logistics, corporate, construction, telecommunication and information technology services.

OTHER SERVICES

The Services Provider shall provide the Services Recipient with:

- Supply Procurement – provision of demand planning, management and procurement, vendor and inventory management, process development, data management, warehousing, waste management and investment recovery.
- Customer Services Operation – provision of bill production and dispatch and settlements service, as well as data services related to field-based service orders.
- Information Management – provision of infrastructure operations, including a variety of activities such as system testing and integration, Internet and database management services, as well as services related to mainframe infrastructure operations, end user and desk-top support.

<u>Schedule "B"</u>

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix C

Hydro One Networks Inc.

Service Provision to:

Hydro One Remote Communities Inc.

2007

(Utility operations services, including line maintenance, forestry, station maintenance, meter services, safety and environment, etc.)

THIS MASTER AGREEMENT made in duplicate as of the 1st day of January, 2007 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.

- and -

HYDRO ONE REMOTE COMMUNITIES INC.

1.0 PREFACE

This Master Agreement and the subsequent individual contracts hereunder are intended to identify the services (collectively, the "Services") that are to be provided to Hydro One Remote Communities Inc. (hereinafter referred to as the "Services Recipient") by Hydro One Networks Inc. (hereinafter referred to as the "Services Provider") in accordance with the terms and conditions herein.

This Master Agreement serves to provide the general commercial terms and conditions that will govern each individual contract (the "Contract") to be agreed upon and executed by the Services Recipient and the Services Provider. Each Contract shall be uniquely numbered, shall specifically describe the individual Services that shall be provided by the Services Provider to the Services Recipient, reference performance targets and reporting requirements and may specify supplementary or different commercial terms and conditions, such as remedies for default, that take precedence over the terms and conditions of this Master Agreement.

Subject to the termination rights in the immediately following paragraph and in Section 6.0 herein, this Master Agreement and the Contracts executed hereunder (except as may be otherwise provided in any of the said Contracts) shall be effective as of the Effective Date and shall continue in full force and effect for a period of 2 years thereafter. In the event that the parties agree to extend the term of a Contract beyond the 2-year period contemplated herein, this Master Agreement shall continue to be in full force and effect for such extended period for purposes of the said Contract.

In the event that either party decides to cease carrying on the business of performing the type of work activities that constitute any portion of the Services under any Contract, it shall provide the other party with 6 months' prior written notice and on the first business day after expiry of the said 6-month period, all Contracts pertaining to the type of work activities which the said party has decided to cease carrying on shall be deemed to be terminated and the Services Recipient shall have no further obligation to the Services Provider other than to pay the Services Provider any monies then due and owing to the Services Provider because of any performance of the Services Provider's obligations completed up to the effective date of such termination plus reasonable costs incurred by the Services Provider as may be agreed upon by the parties, provided that the Services Recipient's liability under this paragraph shall not exceed the price to be paid for the Services as stipulated in the said Contract.

2.0 DEFINITIONS

In the Contracts and this Master Agreement, including the recitals and Schedules hereto, in addition to terms defined elsewhere in this Master Agreement or the Contracts, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

(a) **"Contract Time"** means the time stipulated in any Contract from commencement of the Services to Substantial Performance of the Services.

(b) **"Substantial Performance of the Services"** means the point at which the Services are ready for use or are being used by the Services Recipient for the purpose intended.

(c) **"Total Performance"** means the point at which all of the following have occurred, where applicable:
- Project Completion Report has been received by the Services Recipient from the Services Provider;
- Test Certificate and Permits have been provided by the Services Provider to the Services Recipient;
- the Services Provider has updated the drawings for the Services to "AS BUILT" and has provided the said updated drawings to the Services Recipient.

3.0 SERVICES

The Services Provider shall provide the Services Recipient with the following Services as may be required by the Services Recipient from time to time and as may be agreed upon by both parties in a Contract, which Contract shall be in the form attached hereto as Schedule "C":

- Provincial Lines services
- Forestry services
- Drafting services
- Environmental Land Assessment and Remediation services
- Fleet services
- Flight Safety services
- Safety services
- Training services
- Meter services
- Station Maintenance: Technical Support services
- Approval of plans, drawings and specification of installation work
- Engineering and Construction Services
- Joint Use services

4.0 FEES PAYABLE

(a) The price for the performance of the Services described in each Contract shall be as specified in the relevant Contract and shall include any sales and use taxes as may be applicable, which taxes shall be shown separately in the said Contract. In the event that the parties agree that the Services Recipient shall pay the Services Provider for the Services on a time and materials basis, such time and materials basis shall be in accordance with the Services Provider's 2007-2008 hourly rates by job category and fleet rates, which hourly rates and fleet rates may be amended from time to time by mutual agreement of the parties. The parties acknowledge and agree that the Services Recipient has received the Services Provider's 2007-2008 hourly and fleet rates from the Services Provider.

The parties agree that the price for the Services described in each Contract shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party or by direct time reporting through Hydro One Inc.'s payroll system.

The parties acknowledge and agree that some Contracts may contain holdback provisions that may be based upon performance or other criteria as may be agreed upon, as well as provisions dealing with bonuses and/or penalties.

(b) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the *Excise Tax Act (Canada)*, as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services under the Contracts to be made for nil consideration for Goods and Services Tax purposes.

5.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

(i) it has all the necessary corporate power, authority and capacity to enter into this Master Agreement and to perform its obligations hereunder;

(ii) the execution of this Master Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider;

(iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services; and

(iv) all material, tools, machinery and equipment provided by the Services Provider to the Services Recipient as part of the Services shall be new and of a quality best suited to the purpose required and their use subject to the approval of the Services Recipient.

(b) The Services Recipient represents and warrants that:

(i) it has all the necessary corporate power, authority and capacity to enter into this Master Agreement and to perform its obligations hereunder; and

(ii) the execution of this Master Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

6.0 PERFORMANCE OF THE SERVICES

(a) **Access to Site:** The Services Recipient shall provide the Services Provider with an opportunity to visit and examine the site at which the Services are to be performed prior to the execution of any Contract for the said Services. Upon execution of any Contract, the Services Provider shall be deemed to have represented and warranted, along with the representations and warranties in Section 5.0(a) above, that the Services Provider has visited and examined the site at which the Services are to be performed under the said Contract and that the Services Provider has satisfied itself as to the form and nature of the site, the quantities and nature of the Services to be performed, the labour conditions existing in the area for the Services involved, facilities present on site, access to the site, the seasonal conditions limiting access to the site, the materials necessary for the performance of the Services, and any restrictions or barriers present at the site that would impact the performance of the Services and which the Services Provider was able to reasonably detect upon examination of the site.

(b) **Compliance with Standards, Specifications and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with all statutes, regulations, by-laws, standards and codes as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services identified in each Contract.

The Services Provider shall also comply with the General Standards and Specifications set out in Schedule "A" attached hereto in its performance of the Services, as may be applicable.

The Services Provider shall be responsible for coordinating all related work activities to be performed under all the Contracts.

(c) **Input from Services Recipient:** The Services Recipient shall cooperate and provide any required input as might be requested by the Services Provider, on a timely basis, to facilitate the performance of the Services by the Services Provider. In addition, the Services Recipient shall disclose to the Services Provider on a timely basis any information within the Services Recipient's possession or control which may reasonably affect the ability of the Services Provider to meet its obligations under this Master Agreement and the Contracts.

(d) **Constructor:** Unless otherwise specified in any executed Contract, the parties acknowledge and agree that the Services Provider shall be the "Constructor" of the Services performed under any executed Contract within the meaning of the Occupational Health and Safety Act, R.S.O. 1990, c. 0.1, as amended and the regulations thereunder and shall have all of the responsibilities and liabilities of a "Constructor".

(e) **Safety and Security Measures:** When any part of the Services under any Contract is to be performed at the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(f) **Cleanup:** The Services Provider shall maintain the location at which the Services are performed in a tidy condition and free from the accumulation of waste products and debris, other than that caused by the Services Recipient, its contractors or their respective employees. Upon completion of the Services, the Services Provider shall remove the material, tools, machinery and equipment and waste products and debris, other than those resulting from the work of the Services Recipient, its contractors and their respective employees.

(g) **Review and Inspection of the Services:** The Services Recipient shall have access to the Services at all times. The Services Provider shall provide sufficient, safe, and proper facilities at all times for the review of the Services by the Services Recipient. The Services Recipient may order any portion or portions of the Services to be examined to confirm that such work is in accordance with the requirements of this Master Agreement and the relevant Contract. If the work is not in accordance with the requirements of this Master Agreement and the relevant Contract, the Services Provider shall correct the work and pay the cost of examination and correction. If the work is in accordance with the requirements of this Master Agreement and the relevant Contract, the Services Recipient shall pay the cost of examination and restoration. No payment by the Services Recipient under the relevant Contract shall constitute an acceptance of any portion of the Services which are not in accordance with the requirements of this Master Agreement and the relevant Contract.

(h) **Defective Services:** The Services Provider shall promptly remove from the site at which the Services have been performed and replace or re-execute defective work that has been rejected by the Services Recipient as failing to conform to this Master Agreement and/or the relevant Contract whether or not the defective work has been incorporated in the Services and whether or not the defect is the result of poor workmanship, use of defective products, or damage through carelessness or other act or omission of the Services Provider. The Services Provider shall promptly make good other contractors' work destroyed or damaged by such removals or replacements at the Services Provider's expense. If, in the reasonable opinion of the Services Recipient it is not expedient to correct defective work or work not performed as provided in this Master Agreement and/or the relevant Contract, the Services Recipient may deduct from the amount otherwise due to the Services Provider the difference in value between the work as performed and that called for by this Master Agreement and the relevant Contract. If the Services Provider and Services Recipient do not agree on the difference in value, they shall follow the dispute resolution procedures outlined in Section 8.0 herein.

(i) **Meetings:** The parties agree to meet quarterly after the Effective Date to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to each Contract.

(j) **Right to Terminate Contract:** The Services Recipient may terminate any Contract, without cause and without any penalty to it, at any time by providing written notice to the Services Provider. Upon termination in accordance with this clause, the Services Recipient shall have no further obligation to the Services Provider other than to pay the Services Provider any monies then due and owing to the Services Provider because of any performance of the Services Provider's obligations completed up to the effective date of such termination plus reasonable costs incurred by the Services Provider as may be agreed upon by the parties, provided that the Services Recipient's liability under this clause shall not exceed the price to be paid for the Services as stipulated in the said Contract.

(k) **Emergency Priority:** Upon determination by the Services Recipient that the Services Recipient is in an emergency situation, the Services Provider shall give first priority to responding to the said emergency, in priority over any emergency response commitments that the Services Provider may have to a third party.

7.0 CHANGES TO SERVICES

Either party may request a change to the scope of work specified in each Contract including work already in progress in accordance with this Section.

If either party desires a change in the work described in any individual Contract, it shall complete and submit to the other party's Contract manager identified in the relevant Contract, a Contract Change Notification Form (the "CCNF") in the form attached hereto as Schedule "B". The CCNF shall identify the reasons and impact (cost and schedule) of the change. The other party shall respond to the CCNF no later than 10 business days after receipt thereof. In the event that the parties agree with the change in the scope of work, price and/or time for completion, the parties shall execute the CCNF and the executed CCNF shall be attached to the relevant Contract as a schedule thereto.

In the event that the parties agree on the change in the scope of work but do not agree on a revised price for the changed scope of work, the price shall be fixed on a time and materials basis in accordance with the Services Provider's 2007-2008 hourly rates and fleet rates as may be amended pursuant to this Agreement and the CCNF shall be executed by the parties accordingly. The Services Provider shall provide the Services Recipient with an invoice for the said changed scope of work that is payable on a time and materials basis and the invoice shall include a description of the work performed, a breakdown of the number of hours worked and applicable hourly rates. The Services Provider shall also provide to the Services Recipient such other information and supporting documentation as the Services Recipient may reasonably require. Such invoices, information and supporting documentation shall at all reasonable times be open to audit, inspection and copying by the Services Recipient and shall be preserved and kept available by the Services Provider for audit by the Services Recipient until the expiration of two years from the completion date of the changed scope of work.

Unless otherwise specified in the relevant Contract, the Services Provider shall not be obligated to carry out any change in the scope of work and the Services Recipient shall not be obligated to pay for any change in the scope of work unless and until the relevant CCNF has been executed.

8.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between the parties in connection with the interpretation, performance, construction or implementation of this Master Agreement or any Contract that cannot be resolved by a Director from each party (collectively "Dispute"), other than a Dispute regarding any change to the scope of work activities processed under Section 7.0 above, shall be settled in accordance with this Section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents from each party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the parties shall submit the Dispute in writing to the President of Hydro One Inc. for resolution.

9.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) **Confidentiality**: Each party (the "Receiving Party") shall maintain in strict confidence this Master Agreement, the Contracts and the existence and contents thereof respectively and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Master Agreement and/or the Contracts from the other party (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal, financial or professional advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended) and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "F" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 9.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended. The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;

(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;

(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;

(iv) is or becomes public knowledge through no fault or omission of, or breach of this Master Agreement or the Contracts by, the Receiving Party or the Receiving Party Representatives; or

(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process, including, without limitation, an order of or legal process involving a regulatory authority such as the Ontario Energy Board.

The parties acknowledge and agree that the Confidential Information (other than this Master Agreement and the Contracts which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the Confidential Information it has disclosed to the Receiving Party.

The Receiving Party agrees that it shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Master Agreement and the Contracts), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) **Intellectual Property:** Unless otherwise agreed, the Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to the Services Recipient by the Services Provider in accordance with any Contract and, subject to applicable legislation, and notwithstanding clause 9.0(a) above, the Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) **Survival of Obligations:** The obligations in this Section 9.0 shall forever survive the termination or expiration of this Master Agreement and the Contracts.

10.0 INSURANCE

The Services Provider shall maintain in full force and effect during the term of any executed Contract and with financially responsible insurance carriers, the following insurance coverage and the insurance coverage specified in Schedule "E" attached hereto as may be applicable for any Services and as shall be specified in the relevant Contract for the said Services:

(i) Workers Compensation as required by *the Ontario Workplace Safety and Insurance Act, 1997,* S.O. 1997, c.16, Schedule A, as amended or similar applicable legislation covering all persons employed by the Services Provider for the Services performed under any executed Contract. For U.S. employees, appropriate State Workers Compensation must be carried including Employer's Liability for a minimum limit of $5,000,000 U.S., with a Foreign Coverage Endorsement and, to the extent applicable, Jones Act and U.S. Longshoreman's and Harbor Workers coverage and FELA. To achieve the desired limit, umbrella or excess liability insurance may be used. A waiver of subrogation shall be provided by the insurers to the Services Recipient.

(ii) Automobile Liability Insurance, covering all licensed motor vehicles owned, rented or leased and used in connection with the Services to be performed by the Services Provider under any executed Contract covering Bodily Injury and Property Damage Liability to a combined inclusive minimum limit of $5,000,000 and mandatory Accident Benefits. To achieve the desired limit, umbrella or excess liability insurance may be used.

(iii) Commercial General and Excess Liability Insurance with limits of $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limit, umbrella or excess liability insurance may be used. This coverage shall specifically include, but not be limited to, the following:

a. Blanket Contractual Liability;
b. Damage to property of the Owner including loss of use thereof;
c. Pollution Liability coverage on at least a Sudden and Accidental basis;
d. Products & Completed Operations to be continuously maintained through the operational liability insurance.
e. Employer's Liability;
f. Non-Owned Automobile Liability; and,
g. Broad Form Property Damage

Prior to the commencement of the performance of the Services under any executed Contract, the Services Provider shall provide to the Services Recipient's representative and address noted immediately below, evidence of the minimum coverages required under this Section 10.0 in the form attached hereto as Schedule "D", noting the policy number and term and executed by a duly authorized representative of their respective insurers.

Manager, Risk and Insurance, Hydro One Networks Inc. 483 Bay Street, South
Tower TCT 08, Toronto, Ontario M5G 2P5

With the exception of subparagraph (ii) above, all insurance coverages noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the Services Recipient.

The Services Recipient shall be included as a Named Insured subject to the Sole Agent provision under coverages noted in subparagraph (iii) above, but only to the extent to which the Services Provider is liable to the Services Recipient for breach of its obligations under the relevant

Contract. In addition, the parties acknowledge and agree that the insurance coverages noted in subparagraph (iii) above shall contain a cross liability clause and a severability of interests clause.

The parties further acknowledge and agree that the Insurance coverage described in this Section and provided for the Services Provider shall not be invalidated by actions or inactions of others.

11.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Master Agreement and the Contracts and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Master Agreement, neither party shall be liable for any special, indirect or consequential damages or for economic loss, incurred by the other or by any third party claiming through or under the other.

The foregoing paragraph shall forever survive the termination or expiration of this Master Agreement and the Contracts.

12.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Master Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay St.
North Tower, 14th Floor, A8
Toronto, Ontario
M5G 2P5
Attention: Una O'Reilly
Telephone: (416) 345-6698
Telecopier: (416) 345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor, G3
Toronto, Ontario
M5G 2P5
Attention: Greg Van Dusen
Telephone: (416) 345-5722
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Master Agreement and the Schedules attached hereto shall be directed to the attention of the authorized representatives noted above and all correspondence, reports, documents and/or other communication concerning any Contract and the Services to be performed thereunder shall be directed to the attention of the Contract Managers specified in the relevant Contract. Any notice permitted or required to be given hereunder and/or pursuant to any Contract shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

13.0 FORCE MAJEURE

Except for the payment of any monies required hereunder, neither party shall be deemed to be in default of this Master Agreement or any Contract where the failure to perform or the delay in performing any obligation is due to a cause beyond its reasonable control, including, but not limited to, an act of God, act of any federal, provincial, municipal or government action, or order of court or administrative or regulatory authority, civil commotion, strikes, lockouts and other labour disputes, fires, floods, sabotage, earthquakes, storms, ice storms and epidemics. As soon as a party anticipates that a force majeure event may occur which will delay or prevent it from performing any of its obligations under this Master Agreement or any Contract, it shall promptly notify the other party and shall exercise all reasonable efforts to mitigate or limit the effect on the other party.

Once a party becomes subject to such an event of force majeure, it shall promptly notify the other party of its inability to perform, or of any delay in performing, due to an event of force majeure and shall provide an estimate, as soon as practicable, as to when the obligation will be performed. The party subject to the force majeure event shall also continue to furnish timely reports to the other party with respect to the force majeure event during the continuation of the said event and the said party shall exercise all reasonable efforts to mitigate or limit damages to the other party. The party subject to the force majeure event shall use its best efforts to continue to perform its obligations under this Master Agreement or any Contract, as the case may be, and to correct or cure the event or condition excusing performance and when the said party is able to resume performance of its obligations thereunder, it shall give the other party written notice to that effect and shall promptly resume performance thereunder. The time for performing the obligation shall be extended for a period equal to the time during which the party was subject to the event of force majeure. The parties shall explore all reasonable avenues available to avoid or resolve events of force majeure in the shortest time possible.

Notwithstanding the two preceding paragraphs, the settlement of any strike, lockout, restrictive work practice or other labour disturbance constituting a force majeure event shall be within the sole discretion of the party involved in such strike, lockout, restrictive work practice or other labour disturbance and nothing in the two preceding paragraphs shall require the said party to mitigate or alleviate the effects of such strike, lockout, restrictive work practice or other labour disturbance.

14.0 ASSIGNMENT

Neither this Master Agreement nor any Contract nor the rights and obligations under each thereof shall be assigned by either party hereto without the prior written consent of the other, which consent shall not be unreasonably withheld. Subject to the foregoing, this Master Agreement and each Contract shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

15.0 AMENDMENTS

Any amendment, modification or supplement to this Master Agreement shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Master Agreement. Notwithstanding the foregoing, the parties acknowledge and agree that the Services Recipient shall be entitled to unilaterally change the General Standards and Specifications attached hereto as Schedule "A" provided however that the parties shall negotiate in good faith the effect of any such changes to the scope of work in any relevant Contract, time for completion of the said scope of work and the price therefor, in accordance with the process outlined in Section 7.0 above.

16.0 ENTIRE AGREEMENT

This Master Agreement, together with Schedules "A", "B", "C", "D", "E" and "F" attached hereto, represents the entire agreement between the parties hereto respecting the subject matter hereto and supersedes all prior agreements, understandings, discussions, negotiations, representations and correspondence made by or between them respecting the subject matter hereto.

17.0 CONFLICTS

In the event of any conflict between this Master Agreement and Schedules "A", "B", "C", "D", "E" and "F", the provisions of the former shall prevail. In the event of any conflict between this Master Agreement and any executed Contract, the provisions of the latter shall prevail. In the event of any conflict amongst the Schedules, then the Schedules shall take precedence in the following order: (i) Schedule "C", (ii) Schedule "D"; (iii) Schedule "B"; (iv) Schedule "A"; (v) Schedule "E" and (vi) Schedule "F".

18.0 GOVERNING LAW

This Master Agreement and the Contracts shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

19.0 SCHEDULES

Schedules "A", "B", "C", "D", "E" and "F" attached hereto are to be read with and form part of this Agreement.

20.0 COUNTERPARTS

This Master Agreement and the Contracts may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Master Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE REMOTE COMMUNITIES INC.	**HYDRO ONE NETWORKS INC.**
Name: Myles D'Arcey	Name: Maureen Wareham
Title: SVP, Customer Operations	Title: Corporate Secretary (Acting)
I have authority to bind the corporation.	I have authority to bind the corporation.

Schedule "A"

GENERAL STANDARDS AND SPECIFICATIONS

hydro one

REVISION HISTORY

Date	Revision No.	Modification	Comments

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GSS #1 USED, REUSABLE AND WASTE MATERIALS

1.1 DEFINITIONS

1.1.1 Reusable Material

Where practical, the Services Provider shall reuse and re-deploy all material that is removed from service, provided such material is still in good operating condition and satisfies the criteria indicated in this GSS #1.

1.1.2 Waste Material

All other material that is removed from service will be considered to be waste material.

1.1.3 Recycling

Recycling means using waste material for purposes other than those for which the material was originally intended: it does not include destruction (such as incineration or burning as a supplementary fuel) or use as land fill.

1.2 EXPECTATIONS

Costs for the management of used material that is associated with capital projects, including the disposition of such material for re-deployment, re-use and/or disposal, shall be identified in each Contract, where applicable (e.g. the cost to pickup, transport and dispose of PCB fluids and contaminated waste).

The Services Provider shall handle all reusable material removed from service in a manner that is consistent with the Contract (where identified) and in accordance with applicable legislation, statutes, by-laws, codes, guidelines, regulations, and Hydro One procedures. Such material shall be stored in a safe and secure manner to minimize any risk of physical damage and/or of environmental or health and safety impacts associated with such damage, pending re-deployment or shipment to storage.

The Services Provider shall manage and dispose of waste material in a manner that is consistent with the Contract (where identified) and in accordance with applicable legislation, statutes, by-laws, codes, guidelines, regulations, and Hydro One procedures. Preference will be given, where practical, to disposal options that maximize the potential for recycling.

1.3 CRITERIA FOR USED MATERIALS

Material	Criteria and Action
Poles	• Distribution poles shall be less than 16 years old • Transmission poles shall be less than 12 year old • Penta-treated poles shall not be reused • All wood poles no longer required by the Services Recipient shall be returned to the appropriate service/operations centre. • All wood poles no longer required by the Services Recipient shall be disposed of appropriately.

Material	Criteria and Action
Pole-Mounted Transformers	• Must be no older than 1974 • If less than 200ppm PCB, a pole-mounted transformer shall be drained, refilled and re-tested after 2 years • If bushings are side-mounted they shall be recycled • Pole-Mounted Transformers shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, they shall be returned for repair • If a transformer fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Pad-mount Transformers	• All such transformers shall be returned for repair • If less than 200ppm PCB, a pad-mounted transformer shall be drained, refilled and re-tested after 2 years • Pad-mounted transformers shall be visually inspected. If the inspection indicates no damage to the coil, they shall be returned for repair • If a transformer fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Line Voltage Regulators	• This includes any 50A line regulator retained for parts; all others shall be returned for repair • If less than 200ppm PCB, line voltage regulators shall be drained, refilled and re-tested after 2 years • Line voltage regulators shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, they shall be returned for repair • If a regulators fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Oil Circuit Reclosers	• If less than 200ppm PCB, the reclosers shall be drained, refilled, and re-tested after 2 years • Reclosers shall be visually inspected (remove cover). If the inspection indicates that there is no damage, they shall be returned for repair • If a recloser fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Metering Transformers / Units	• If less than 200ppm PCB, the units shall be drained, refilled and re-tested after 2 years • The units shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, it shall be returned for repair • If a unit fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Capacitors	• No PCB or Dielektrol I- or II-filled capacitors shall be reused • Capacitors shall not have an unknown PCB content unless permission is obtained from the Services Recipient. Some capacitors manufactured before January 1981 may contain PCB over 50 ppm.
Primary Conductors	• If less than 3/0, primary conductors shall be reused for extensions where the main line is of the same size • Before reusing, #2 shall be inspected for deterioration in the core • All other conductors shall be reused
Secondary Conductors/ Underground Cable	• Secondary Conductors/Underground Cables shall be reused if they pass an asset condition test • The units must contain no splices (in the underground cable) that test greater than 50 mg/kg PCB. In addition, end sections must not have come from terminations that test greater than 50 mg/kg PDB. • All secondary conductors shall be reused • No underground cables shall be reused if they are more than 10 years old
Submarine Cable	• No submarine cable shall be used if it is more than 5 years old

Material	Criteria and Action
Insulators	• All single piece porcelain pin insulators shall be reused (not other porcelain insulators): the intent is to replace insulators with silicone (polymer) types on 115 kv and 230 kv, where practical • Epac insulators shall not be reused • Cob porcelain post insulators shall not be reused
Cross-arms	***Distribution:*** • Cross-arms shall be reused if no apparent cracking or excessive aging is evident
	Transmission: • All wooden cross-arms shall be removed and disposed • All steel cross-arms shall be reused
Spool Bolts	• All spool bolts shall be reused
Switches	***Distribution:*** • No Kearney switches nor rigid polymeric insulator-type switches shall be reused
	Transmission: • All shall be 115 kV & 230 kV in-line polymeric switches • Only those switches that have tested satisfactorily shall be reused
Insulating Oil	• All insulating oil is required to meet specification for Voltesso 35 Category "B" oil OR have the potential to be upgraded to meet this specification • Insulating oil must contain less than 50 mg/kg PCB by laboratory test

1.4 FINANCIAL TREATMENT OF USED MATERIAL

The Services Provider shall report all units removed from service. When used materials are reused for capital or maintenance work, the materials shall be charged to the work as if the material was new.

1.5 INFORMATION REQUIREMENTS

The Services Provider shall record and report the following information to the Services Recipient according to a schedule specified in the applicable Contract(1).

- Transformer Units by MVA/kVA and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Regulator/Rabbit Units by kVA and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Recloser Units by voltage and interrupting rating
- Switches by manufacturer type and voltage rating
- Capacitor Units by total MVA/kVAR, including voltage, number of phases and control type, whether installed, salvaged or disposed as waste (new or used material)
- Transmission line structures and distribution pole units by type (steel or wood pole), height, age, ownership (Hydro/Bell Canada/MEU), Bell Canada I.D. (exchange, route and pole number), structure number
- Conductor Units by size, type and length, whether installed, salvaged or disposed as waste (new or used material)
- Cable size, type, length and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Record or retained material, including volumes scrapped, reused or repaired and reused.

(1) Note: The information listed above is required for accounting purposes at the plant.

1.6 WASTE MATERIAL

For waste material that is classified as either hazardous or as liquid industrial, the Services Provider shall follow specific requirements. These requirements are detailed in the appropriate legislation (e.g., *Environmental Protection Act, Occupational Health & Safety Act*) and internal policies/standards/procedures (e.g., Waste Management Manual). Records of hazardous waste volumes shipped to disposal shall be reported to the Services Recipient and such records shall be maintained according to established records management. All hazardous waste material shall be handled and managed with due regard for worker and public health and safety.

GSS #2 ENVIRONMENT, HEALTH & SAFETY REQUIREMENTS

2.1 GENERAL STATEMENT OF COMPLIANCE AND REQUIREMENTS

The Services Recipient expects to receive the same level of compliance, where applicable, for services provided under all Contracts. As a minimum, the Services Provider shall comply with the following:

- Federal and Provincial legislation;
- Municipal by-laws;
- The Services Recipient's Safety Rules and Policies;
- All legacy Ontario Hydro policies, procedures and standards still applicable to the Services Recipient;
- Policies approved by the Services Recipient's Board of Directors;
- The Services Recipient's Environment, Health & Safety Management policies, procedures and associated standards; and
- The Services Recipient's Policy for Health & Safety Incident Management.

2.2 ENVIRONMENTAL REQUIREMENTS

2.2.1 General Requirements for Management of the Environment

For managing the environment, the Services Provider shall abide by the following:

a) The Services Provider shall design, construct, operate, maintain and decommission the Services Recipient's facilities in accordance with standards to be developed by the Services Recipient and made available to the Services Provider.

b) The Services Provider shall perform all work on behalf of the Services Recipient in a manner that is consistent with the principles of an environmental management system including, as a minimum:
   - Assigning and communicating individual accountability and responsibility for the environment;
   - Engaging qualified employees and agents (i.e. with respect to knowledge, training and experience to perform the work assigned) to perform the work;
   - Having emergency preparedness and response capability suitable to the range of issues that could be encountered during the course of the work detailed in the Contract;
   - Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the Contracted services;
   - Reporting environmental incidents, performing incident investigations and implementing corrective actions in response to an incident; and
   - Periodically reviewing environmental management processes and making improvements, as necessary.

c) The Services Provider shall consider the environmental implications of all work and integrate environmental considerations into its plans for all work that could have an adverse effect on the environment.

d) In performing the services, the Services Provider shall:
   - Use materials, products and equipment that are government-approved, industry-accepted and sustainable (i.e., from environmental, economical, social perspectives). The Services provider shall give preference, where practical, to materials and products that have low toxicity and do not contain substances that are included on Schedule 1 (List of Toxic Substances) of the *Canadian Environmental Protection Act* or on the Priority Substances Lists 1 and 2.
   - Maximize the efficient use of resources;
   - Be energy efficient; and
   - Conserve heritage resources.

e) The Services Provider shall, when included in the project scope, prepare and implement project-specific environmental specifications when the prevention or mitigation of predicted environmental impacts can only be assured by the application of a specific damage prevention or mitigation approach. Such environmental management specifications will be consistent with applicable standards.

f) The Services Provider shall prepare and provide to the Services Recipient, project-specific, As-Constructed Reports for all projects that require any one or more of the following, where the Services Recipient and the Services Provider shall mutually determine which environmental authorities or industry or legislative standards shall be used in developing such reports:

- Environmental permits;
- Environmental considerations or special commitments;
- Access agreements, construction property agreements and special conditions that contain a record of the final environmental state of the project;
- Documentation of significant environmental situations or activities; and
- Property rights summaries.

g) The Services Provider shall provide to the Services Recipient, the records identified in (b), (e) and (f).

2.2.2 Environmental Incident Management

The Services Provider shall consistently respond and report environmental incidents and ensure that all such incidents involving Distribution or Transmission assets and lands are managed effectively. Included as "environmental incidents" are:

- Vandalism, natural events (such as lightning, ice, and wind) and animal activity;
- Accidental or inadvertent public contact with electrical system assets or equipment (such as motor vehicle accidents, ladders into lines);
- Mechanical/electrical failure for no apparent reason or unknown cause;
- Asset management standards that are subsequently shown to have contributed to the incident; and
- Operation or maintenance activities in accordance with accepted standards that would not normally be expected to cause leaking, equipment failure or malfunction.

The Services Provider shall document all environmental incidents (such as spills and fires) involving the Services Recipient's assets and/or lands (owned or easement) (e.g., complete a Hydro One Environmental Incident Report). The Services provider shall enter this information into the Web Environmental Incident Collector (WebEIC) database and/or any other similar database, as directed by the Services Recipient.

The Services Provider shall consistently respond to, and report, environmental incidents. The Services Provider shall also ensure that all environmental incidents involving the Service Recipient's assets and land are managed effectively.

2.3 HEALTH & SAFETY

2.3.1 Potential Hazards

There are two significant hazards associated with work on the Services Recipient's assets:

- Hazards inherent to working in proximity to electrical equipment; and
- Hazards inherent to working at heights.

The Services Provider may also work in buildings or at sites where hazardous substances are present. Inventories and assessments of potentially hazardous or hazardous substances have been completed for the majority of the Services Recipient's sites; they are available to the Services Provider on request. All requests should be made locally.

The Services Provider shall manage all hazards associated with all Contracts with the Services Recipient.

2.3.2 General Requirements for the Management of Health & Safety

The Services Provider shall perform all work on behalf of the Services Recipient in a manner that is consistent with the principles of a health and safety management system including, as a minimum:

(a) Assigning and communicating individual accountability and responsibility for health and safety;
(b) Engaging qualified employees and agents (i.e. with respect to knowledge, training and experience to perform the work assigned) to perform the work;
(c) Having emergency preparedness and response capability suitable to the range of issues that could be encountered during the course of the work detailed in the Contract;
(d) Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the Contracted services;

(e) Reporting safety events, performing event investigations and implementing corrective actions in response to an event;
(f) Periodically reviewing health and safety management processes periodically and making improvements, as necessary; and
(g) Submitting the records identified in (e) and (f) to the Services Recipient.

The Services Provider shall ensure the protection of the public in the performance of all work for the Services Recipient.

2.3.3 Health & Safety Event Management

The Services Provider shall consistently respond and report all health and safety events involving the Services Recipient staff and/or members to the Services Recipient. Included as health and safety events are:

- Vandalism, natural events (such as lightning, ice, and wind) and animal activity;
- Accidental or inadvertent public contact with electrical system assets or equipment (such as motor vehicle accidents, ladders into lines);
- Mechanical/electrical failure for no apparent reason or unknown cause;
- Asset management standards that are subsequently shown to have contributed to the event; and
- Operation or maintenance activities in accordance with accepted standards that would not normally be expected to cause leaking, equipment failure or malfunction.

Schedule "B"

CONTRACT CHANGE NOTIFICATION FORM (No. xxx)

Date issued: xx-xxx-xx

Contract #		
Services Description		
Project ID	**Services Recipient**	**Services Provider**
Scope Change		
Reason for Change		
Schedule/Delivery Impact		
Impact on Price	**Old Contract Price:** **New Contract Price:**	
Approvals	**Hydro One Networks Inc.**	**Hydro One Remote Communities Inc.**
Effective Date of Change:		
Proposed By:		
Date:		
Reviewed By:	(Contract manager)	(Contract manager)
Date:		
Approved by:	(Authorized Signatory)	(Authorized Signatory)
Date:		

Schedule "C"

CONTRACT No. _______

THIS CONTRACT made this ____ day of _________, 2007 between **HYDRO ONE NETWORKS INC.** (the "Services Provider") and **HYDRO ONE REMOTE COMMUNITIES INC.** (the "Services Recipient").

WHEREAS the Services Provider and the Services Recipient have entered into a Master Agreement dated ______________ (the "Master Agreement"), which specifies the terms and conditions that govern this Contract;

AND WHEREAS the parties have agreed to enter into this Contract whereby the Services Provider has agreed to provide to the Services Recipient and the Services Recipient has agreed to acquire from the Services Provider, the services more specifically described in section A. below (the "Services"), pursuant to the terms and conditions herein and in the Master Agreement.

NOW THEREFORE in consideration of the terms, conditions and covenants contained herein and in the Master Agreement and other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the parties hereto agree to the following:

A. Description of Services (Describe Scope of Work):

B. Term:

C. Price and Terms of Payment:
Base Price:
Provincial Sales Tax:

D. Exceptions/Additions to terms and conditions in Master Agreement:

E. Service Levels

F. Performance Targets:

G. The managers for this Contract shall be as follows:

Services Provider: Hydro One Networks Inc.
483 Bay Street TCT 8 G3
Toronto, Ontario M5G 2P5

Contract Manager: Name: **Greg Van Dusen**
Title: Director, Work Program Optimization
Tel. No. 416-345-5722
Fax. No. 416-345-6833

Services Recipient: Hydro One Remote Communities Inc.
483 Bay Street, TCT 14 A8
Toronto, Ontario M5G 2P5

Contract Manager: Name: **Una O'Reilly**
Title: Manager, Business Integration
Tel. No. 416-345-6698
Fax. No. 416-345-6356

The parties acknowledge and agree that the above terms and conditions and the terms and conditions contained in the Master Agreement shall govern this Contract except as otherwise agreed above under Section D. and the parties shall hereby be bound by and comply with all of the said terms and conditions.

IN WITNESS WHEREOF, the parties have caused this Contract to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE REMOTE COMMUNITIES INC.	**HYDRO ONE NETWORKS INC.**
Name: Title: I have authority to bind the corporation.	Name: Title: I have authority to bind the corporation.

Schedule "D"

COMMERCIAL GENERAL LIABILITY INSURANCE CERTIFICATE
SUPPLY ONLY TRADES

Issued in favour:				
Insured:				
XXXXXXXXXXXXXXXXXXXXX				
XXXXXXXXXXXXXXXXXXXXX				
XXXXXXXXXXXXXXXXXXXXX				
XXXXXXXXXXXXXXXXXXXXX				
This is to certify that policies of insurance listed below have been issued to the insured named above for the period indicated and cover operations of the insured in connection with the **SERVICES BEING PERFORMED UNDER CONTRACT NUMBER xxxxxxxxxx**				
		Effective	**Expiration**	
	Policy	**Date**	**Date**	
Type of insurance	**Number**	**MM/DD/YR**	**MM/DD/YR**	
Commercial General Liability				$5,000,000
(X) Blanket Contractual Liability				$5,000,000
(X) Broad Form Property Damage				$5,000,000
(X) 3rd Party Property damage including loss of use				
(X) Sudden and Accidental Pollution Liability coverage				
(X) Products and Completed operations				
(X) Employer's Liability				
(X) Non-Owned Automobile Liability				
Automobile Liability				
(X) Owners				$5,000,000

Special Condition

Commercial General Liability policy shall i) include Hydro One Remote Communities Inc. as a named insured subject to sole agent provisions and ii) be primary non-contributing with and not excess of any other insurance available to Hydro One Remote Communities Inc. iii) contain a cross liability and severability of interest clause

The Insurer agrees to notify the certificate holder by registered mail not less than 30 days prior to any material change, which reduces or restricts cover, cancellation, termination or non-renewal.

Date:	
Name of Insurer:	
By: Authorized Official of the Insurance Company	
Print Name and Title of Above Official	

Schedule "E"

ADDITIONAL INSURANCE COVERAGES

1.01 Commercial General Liability and Excess Liability Insurance on an occurrence basis in an amount not less than $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limit, umbrella or excess liability insurance may be used.

Coverage shall specifically include, but not be limited to, the following

i) Blasting, pile driving, caisson work, underground work;
ii) Products & Completed Operations including a provision that such coverage to be maintained for a period not less than 24 months post Final Performance;
iii) Errors and omissions integral to the operation of the Insured;
iv) Tenant's Legal Liability;
iv) Pesticide Liability; and
v) Rail Liability.

1.02 Contractor's Equipment Insurance covering equipment and tools, owned, rented or leased for the full replacement cost of such equipment on an "All Risks" basis including marine based risk subject to normal exclusions.

1.03 Pollution Liability Insurance: When remediation or abatement is included in the work, the Services Provider shall purchase a policy with limits of not less than $5,000,000 per occurrence covering bodily injury and property damage claims, including cleanup costs as a result of pollution conditions arising from the Services Provider's and/or its subcontractors' operations and completed operations. Completed operations coverage will remain in effect for no less than 3 years after final completion. The policy will have a retroactive date before the start of the work. To achieve the desired limit, umbrella or excess liability insurance may be used.

1.04 Errors & Omissions Insurance: Engineering, Architectural, Design or other Professionals or Consultants and the EPCM (Engineering, Procurement, Construction and Maintenance). The Services Provider shall, at all times, maintain in full force and effect professional liability insurance in an amount not less than $10,000,000 aggregate limit covering the period from start of conceptual design through to completion of the project and for a further discovery period of 5 years from the issuance of the certificate of Final Completion.

1.05 Transit insurance (including loading, unloading and storage during the course of transit including storage at secondary processing facilities) against All Risks of physical damage to the property of the Services Recipient in the Services Provider's care, custody and control until such property is received on the Services Recipient's site.

1.06 Aircraft and watercraft liability insurance with respect to owned or non-owned aircraft and watercraft if used directly or indirectly in the performance of the Services, including use of additional premises, shall be subject to limits of not less than $5,000,000.00 inclusive per occurrence for bodily injury, death and damage to property including loss of use thereof and limits of not less than $5,000,000.00 for aircraft passenger hazard. Such insurance shall be in a form acceptable to the Services Recipient. The policies shall be endorsed to provide the Services Recipient with not less than 15 days' notice in writing in advance of cancellation, change, or amendment restricting coverage. To achieve the desired limit, umbrella or excess liability insurance may be used.

1.07 Such other insurance as is mutually agreed upon between the Services Recipient and the Services Provider.

Where any of the above coverages are required for any Contract, the Services Provider shall be bound by and comply with the following:

1. Prior to the commencement of the performance of the Services, the Services Provider shall provide the Services Recipient with a certificate of insurance completed by a duly authorized representative of its insurer certifying that at least the minimum coverages required here are in effect and that the coverages will not be cancelled, nonrenewed, or materially changed by endorsement or otherwise so as to restrict or reduce coverage, without 30 days' advance written notice by registered mail, or courier, receipt required, to:

   Manager, Risk & Insurance Department, Hydro One Remote Communities Inc. 483 Bay Street, TCT8, South Tower , Toronto, Ontario. M5G 2P5

   If any of the coverages are required to remain in force after final payment, an additional certificate evidencing continuation of such coverage will be submitted with the Services Provider's final invoice.

2. All deductibles shall be to the account of the Services Provider.

3. All insurance noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the Services Recipient.

4 A waiver of subrogation shall be provided by the insurers to the Services Recipient for coverages 1.02 (Contractor's Equipment).

6. The Services Recipient shall be included as a Named Insured under coverages noted in 1.03 (Pollution Liability) subject to Sole Agent provisions.

7. Coverages noted in 1.03 (Pollution Liability) shall contain a Cross Liability clause and a Severability of Interests clause.

8. Coverage provided for shall not be invalidated by actions or inactions of others.

Schedule "F"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix D

Hydro One Networks Inc.

Service Provision to:

Hydro One Remote Communities Inc.

2008

(President and CEO services)

THIS AGREEMENT made in duplicate this 1st day of January, 2008 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC.
(the "Services Recipient")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. The term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide chief and executive office and president services to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

3.0 FEES PAYABLE

(a) The annual price for the performance of the Services for the Services Recipient shall be $80,000.00, exclusive of any sales and use taxes, as may be applicable. The said annual price for the Services shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:

- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: The parties shall, after the Effective Date, meet at least twice a year during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement."

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
North Tower, 14th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 14
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Greg Van Dusen**
Telephone: (416) 345-5722
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

13.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

14.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

Name: Maureen Wareham
Title: Secretary
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
have authority to bind the corporation.

Schedule "A"

DESCRIPTION OF SERVICES:

The Services Provider shall provide the Services Recipient with the following services:

- Provide administrative services related to Corporate record-keeping, and signing of contracts and corporate documents that require strategic approval;
- Communicate Hydro One Inc.'s strategic goals, direction and policies to the Services Recipient and ensure that the Services Recipient adheres to these policies, goals and directions; and
- Advocate for the Services Recipient at the Hydro One Inc. level for budgetary items, operational issues and performance goals, and ensure that the Services Recipient's business is understood and communicated at the parent company level.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix E

Hydro One Remote Communities Inc.

Service Provision to:

Hydro One Networks Inc.

2008

(Metering and lines services)

THIS AGREEMENT made in duplicate this 1st day of January, 2008 (the "Effective Date").

BETWEEN:

HYDRO ONE REMOTE COMMUNITIES INC.
(the "Services Provider")

- and -

HYDRO ONE NETWORKS INC.
(the "Services Recipient")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. The term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

Subject to the Services Provider's availability of personnel and resources, which availability shall be determined by the Services Provider in its sole discretion, the Services Provider shall provide metering work, lines work and training for lines work to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

3.0 FEES PAYABLE

(a) The price for the performance of the Services shall be on a time and materials basis in accordance with the Services Provider's 2008-2009 hourly rates by job category, which rates may be amended from time to time by mutual agreement of the parties. The parties acknowledge and agree that the Services Recipient has received the Services Provider's 2008-2009 hourly rates from the Services Provider.

(b) The parties agree that the price for the Services shall be paid by the Services Recipient to the Services Provider by direct time reporting through Hydro One Inc.'s payroll system.

(c) In addition, the Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(d) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(e) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: The parties shall, after the Effective Date, meet at least once during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
North Tower, 14th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 14
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Greg Van Dusen**
Telephone: (416) 345-5722
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

13.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

14.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

M Wareham

Name: Maureen Wareham
Title: Secretary
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
have authority to bind the corporation.

Schedule "A"

DESCRIPTION OF SERVICES:

Subject to the Services Provider's availability of personnel and resources, which availability shall be determined by the Services Provider in its sole discretion, the Services Provider shall provide the Services Recipient with the following services as may be required by the Services Recipient from time to time during the term of this Agreement:

a. Metering/Technician Work:

- update, install, reverify and sample meters
- Smart meter change-outs
- line layout, estimating and staking
- voltage/current surveys and responding to voltage/current complaints

b. Lines Work:

- maintain the Services Recipient's transmission and distribution system in Northwestern Ontario by providing the following activities, as may be requested by the Services Recipient:
- power line maintenance, construction and repair
- trouble Call Response, power restoration and storm damage repairs

c. Training:

- Provide lines apprenticeship program instruction services

<u>Schedule "B"</u>

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix F

Hydro One Networks Inc.

Service Provision to:

Hydro One Remote Communities Inc.

2008

(Joint use services)

THIS AGREEMENT made in duplicate this 1st day of January, 2008 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC.
(the "Services Recipient")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. The term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide joint use services to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

3.0 FEES PAYABLE

(a) The annual price for the performance of the Services for the Services Recipient shall be $25,000.00, exclusive of any sales and use taxes, as may be applicable. The said annual price for the Services shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

(i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and

(iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:

(i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: The parties shall, after the Effective Date, meet at least twice a year during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
North Tower, 14th Floor
Toronto, Ontario M5G 2P5

Attention:	**Una O'Reilly**
	TCT 14
Telephone:	416-345-6698
Telecopier:	416-345-6356

HYDRO ONE NETWORKS INC.
185 Clegg Road.
Markham, Ontario L6G 1B7

Attention:	**Steven Vance**
Telephone:	(905) 946-6210
Telecopier:	(905) 946-6215

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

13.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

14.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: Secretary
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
have authority to bind the corporation.

Schedule "A"

DESCRIPTION OF SERVICES:

The Services Provider shall provide the Services Recipient with the following services in order to assist the Services Recipient with its Joint Use Program:

(a) Support and participate with the Services Recipient's staff in drafting, negotiating, tracking and arranging for execution of joint use agreements for the Services Recipient as required and requested by the Services Recipient;

(b) add, remove and change permits or similar authorizations and update and/or remove documents as required by the Services Recipient;

(c) issue invoices to tenants/licensee for the Services Recipient in accordance with the Services Recipient's joint use agreements and manage the related accounts receivables accordingly;

(d) manage and input information concerning the Services Recipient's joint use agreements into the Services Provider's "Joint Use" database and maintain said information separate from the Services Provider's own joint use information;

(e) liaise with the Services Provider's "Joint Use" database service provider on behalf of the Services Recipient; and

(f) provide training to the Services Recipient's staff with regard to the Database, joint use agreements and other joint use activities, all as requested by the Services Recipient.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

REMOTES FINANCIAL STATEMENT

HISTORIC YEARS (2005, 2006 AND 2007)

Attachment 1 – 2005 Financial Statements
Attachment 2 – 2006 Financial Statements
Attachment 3 – 2007 Financial Statements

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2005

HYDRO ONE REMOTE COMMUNITIES INC.
AUDITORS' REPORT

To the Directors of
Hydro One Remote Communities Inc.:

We have audited the balance sheets of Hydro One Remote Communities Inc. as at December 31, 2005 and December 31, 2004 and the statements of operations, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Hydro One Remote Communities Inc. as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada
April 5, 2006

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in thousands)	**2005**	**2004**
Revenues *(Note 14)*	34,411	31,706
Costs		
Operation, maintenance and administration *(Note 14)*	12,984	10,573
Fuel used for electric generation	15,289	13,017
Depreciation and amortization *(Note 3)*	4,032	4,750
	32,305	28,340
Income before financing charges and provision for payments in lieu of corporate income taxes	2,106	3,366
Financing charges *(Notes 4 and 14)*	1,917	1,618
Income before provision for payments in lieu of corporate income taxes	189	1,748
Provision for payments in lieu of corporate income taxes *(Notes 5 and 14)*	189	1,748
Net income	-	-

See accompanying notes to financial statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (Canadian dollars in thousands)	**2005**	**2004**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts - $533; 2004 - $788)	10,531	11,972
Fuel, materials and supplies	2,829	2,911
	13,360	14,883
Fixed assets *(Note 6)*		
Fixed assets in service	39,156	37,224
Less: accumulated depreciation	16,787	15,101
	22,369	22,123
Construction in progress	2,008	1,629
	24,377	23,752
Other long-term assets		
Regulatory assets *(Note 7)*	8,412	10,145
Long-term accounts receivable (net of allowance for doubtful accounts - $2,213; 2004 - $nil) *(Note 8)*	684	-
Deferred debt costs	114	-
	9,210	10,145
Total assets	46,947	48,780
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 14)*	688	728
Accounts payable and accrued charges	7,299	7,078
Accrued interest	142	289
	8,129	8,095
Long-term debt *(Notes 9, 10 and 14)*	22,312	23,000
Other long-term liabilities		
Employee future benefits other than pension *(Note 11)*	4,563	4,132
Environmental liabilities *(Note 12)*	5,103	7,204
Regulatory liability *(Notes 7 and 14)*	6,840	6,349
	16,506	17,685
Total liabilities	46,947	48,780
Contingency *(Note 16)*		
Shareholder's equity		
Common shares (authorized: unlimited; issued 2) *(Note 13)*	-	-
Retained earnings	-	-
Total shareholder's equity	-	-
Total liabilities and shareholder's equity	46,947	48,780

See accompanying notes to financial statements.

On behalf of the Board:

Tom Parkinson
Chair

Myles D'Arcey
Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in thousands)	**2005**	**2004**
Operating activities		
Net income	-	-
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	3,910	4,621
Remote rate protection revenue variance account	491	3,451
	4,401	8,072
Changes in non-cash balances related to operations *(Note 15)*	650	(2,544)
Net cash from operating activities	5,051	5,528
Investing activities		
Capital expenditures	(2,967)	(2,160)
Environmental expenditures *(Note 12)*	(1,238)	(2,161)
Net cash used in investing activities	(4,205)	(4,321)
Financing activities		
Termination of interest rate swap	(661)	-
Debt issue costs	(114)	-
Other	(31)	-
Net cash used in financing activities	(806)	-
Net change in inter-company demand facility	40	1,207
Inter-company demand facility, January 1	(728)	(1,935)
Inter-company demand facility, December 31	(688)	(728)

See accompanying notes to financial statements.

1. DESCRIPTION OF BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). Hydro One Remote Communities owns and manages electricity supply assets in remote northern communities through 18 distribution systems that are not connected to Ontario's electricity transmission grid operated by Hydro One Networks Inc. (Hydro One Networks), also a wholly owned subsidiary of Hydro One. The Company's business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared using a cumulative breakeven business model and are for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2005 have been prepared and are publicly available.

Rate-setting

The Company's electricity generation and distribution business is subject to regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. The Company's regulatory assets primarily represent costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recognized a regulatory liability related to remote rate protection revenues received in excess of the amounts required to operate the Company on a cumulative breakeven basis, after tax. The Company's regulatory assets and regulatory liability recognized at December 31, 2005 are disclosed in Note 7.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liability into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition and the Remote Rate Protection Revenue Variance Account

Revenues attributable to the delivery of electricity are recognized at the time electricity is delivered to customers. The Company estimates the monthly revenue for the period based on customer history because customer meters are not generally read at the end of each month. These estimates are reconciled to actual customer consumption on a regular basis.

In approving electricity rates for a distributor that delivers electricity to remote customers, the OEB is required to provide rate protection for prescribed classes of customers by reducing the electricity rates that would otherwise apply in accordance with rules established pursuant to the *Ontario Energy Board Act, 1998*. Such remote rate protection amounts are collected by the Independent Electricity System Operator (IESO) through a charge to all Ontario customers. In 2002, *Ontario Regulation 442/01 – Rural or Remote Electricity Rate Protection* directed the method of developing the annual amount of rate protection and set the annual amount for 2002 and subsequent years at $21,108 thousand.

Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operating result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Revenue Variance Account.

The balance in the Remote Rate Protection Revenue Variance Account is subject to future disposition by the OEB. On October 26, 2005, Hydro One Remote Communities made an application to the OEB to establish customer rates for 2006. The application also seeks OEB approval to retain the balance in the Remote Rate Protection Revenue Variance Account for rate stabilization purposes. The OEB is expected to issue a decision on this matter during 2006.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). 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 Company provides for payments in lieu of corporate income taxes using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the Company's customers at that time.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by Hydro One Remote Communities to and from the pooled cash accounts. The Company earns interest on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of each month, less 0.02%. Hydro One Remote Communities is charged interest on overdraft inter-company balances based on the same banker's acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent spare parts and construction material for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction.

Some of the Company's generation and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Fixed assets in service consist of generation, distribution and administration and service assets. These asset categories are described below:

Generation

Generation assets are used in the generation of electricity and include hydroelectric equipment, wind turbines, diesel generators and tank farms.

Distribution

Distribution assets are used in the distribution of low-voltage electricity and include lines, poles, switches, transformers, protective devices and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2005 – 6.8%; 2004 – 7.0%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Generation	15 – 50	26
Distribution	15 – 55	40
Administration and service	5 – 50	44

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements, including those that arise as communities are connected to Hydro One Networks' transmission grid, are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Deferred Debt Costs

Deferred debt costs represent debt issuance costs allocated by Hydro One based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts, Premiums and Hedging

Discounts, premiums and hedging gains and losses allocated by Hydro One, based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue, are amortized over the period to the maturity of the related debt.

Employee Future Benefits

Employee future benefits provided by Hydro One Remote Communities include pension, group life insurance, health care and long-term disability.

In accordance with OEB rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Company has recognized a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from the estimates, including changes as a result of future decisions made by the OEB or the Province of Ontario (the Province).

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in thousands)	**2005**	**2004**
Depreciation of fixed assets in service	2,343	2,131
Fixed asset removal costs	122	129
Amortization of regulatory assets	1,567	2,490
	4,032	4,750

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in thousands)	**2005**	**2004**
Interest on long-term debt payable	2,268	1,787
Less: Interest on inter-company demand facility	(268)	13
Interest capitalized to construction in progress	(98)	(171)
Other	15	(11)
	1,917	1,618

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in thousands)	**2005**	**2004**
Income before provision for PILs	189	1,748
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	68	631
Increase (decrease) resulting from:		
Net temporary differences:		
Depreciation and amortization in excess of capital cost allowance	649	897
Environmental expenditures	(447)	(781)
Termination of interest rate swap	(239)	-
Remote rate protection revenue variance account	177	1,246
Employee future benefits other than pension expense in excess of cash payments	108	122
Interest capitalized for accounting purposes but deducted for tax purposes	(35)	(62)
Cash payments for staff reduction program	-	(35)
Other	(172)	(254)
Net temporary differences	41	1,133
Net permanent differences:		
Large corporations tax	68	25
Other	12	(41)
Net permanent differences	80	(16)
Provision for PILs	189	1,748
Effective income tax rate	100.00%	100.00%

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2005, future income tax assets of $5,411 thousand (2004 - $5,370 thousand), based on substantively enacted tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized on an accrual basis rather than under the taxes payable method. As a result, the provision for PILs would have been lower by approximately $41 thousand.

6. FIXED ASSETS

December 31 (Canadian dollars in thousands)	Fixed Assets in Service	Accumulated Depreciation	Construction In Progress	Total
2005				
Generation	29,320	13,983	1,440	16,777
Distribution	5,180	1,258	88	4,010
Administration and service	4,656	1,546	480	3,590
	39,156	16,787	2,008	24,377
2004				
Generation	27,881	12,703	1,374	16,552
Distribution	5,009	1,159	86	3,936
Administration and service	4,334	1,239	169	3,264
	37,224	15,101	1,629	23,752

Financing costs are capitalized on fixed assets under construction, using the allowance for funds used during construction, and were $98 thousand in 2005 (2004 - $171 thousand).

7. REGULATORY ASSETS AND LIABILITY

Regulatory assets and liabilities can arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liability:

December 31 (Canadian dollars in thousands)	**2005**	**2004**
Regulatory assets:		
Employee future benefits other than pension	987	1,316
Environmental *(Note 12)*	7,425	8,829
Total regulatory assets	8,412	10,145
Regulatory liability:		
Remote rate protection revenue variance account	6,840	6,349

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose upon the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One Remote Communities recorded a regulatory asset in the original amount of $3,289 thousand to reflect this regulatory treatment. This regulatory asset has a remaining service life of 3 years (2004 – 4 years) and does not earn a return. In the absence of regulatory accounting, amortization expense in 2005 would have been lower by approximately $329 thousand.

Environmental

The Company provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are recoverable through rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2010. In the absence of regulatory accounting, amortization expense in 2005 would have been lower and operation, maintenance and administration expense would have been higher by $1,238 thousand.

Remote rate protection revenue variance account

The Company has recognized a long-term regulatory liability for remote rate protection amounts received in excess of amounts required to achieve an after-tax breakeven operating result. In the absence of regulatory accounting, revenue in 2005 would have been higher by $491 thousand.

8. LONG-TERM ACCOUNTS RECEIVABLE

During 2005, $684 thousand in current accounts receivable, after inclusion of the related allowance for doubtful accounts, were reclassified from current assets to long-term, reflecting a change in payment terms for certain amounts.

9. LONG-TERM DEBT

December 31 (Canadian dollars in thousands)	**2005**	**2004**
Long-term debt	23,000	23,000
Unamortized discount	(31)	-
Unamortized hedging loss	(657)	-
	22,312	23,000

Long-term debt represents a note issued on May 19, 2005 and payable to Hydro One. The note is denominated in Canadian dollars, bears interest at 5.38% and is due on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999. The original note, which bore interest at a rate of 7.77%, was issued as consideration for the purchase price of Hydro One Remote Communities' net assets.

The discount and hedge loss represent unamortized costs allocated by Hydro One to each of its subsidiaries, including Hydro One Remote Communities, on the basis of each subsidiary's proportionate share of Hydro One's related debt issue.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt is based on year-end quoted market prices for same or similar debt of the same remaining maturities, and is provided in the following table:

December 31 (Canadian dollars in thousands)	**2005**		**2004**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	23,000	24,668	23,000	23,942

1 The carrying amount of long-term debt represents the par value of the note.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2005, appropriate allowances had been made to reflect the risk of potential credit losses.

11. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for Society of Energy Professionals' represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, Hydro One contributed $83 million to its pension plan in respect of 2005 (2004 - $74 million), all of which will satisfy minimum funding requirements. Contributions are payable one month in arrears. A portion of these contributions are attributed to the Remote Communities business. All of the contributions are expected to be in the form of cash. Prior to 2004, Hydro One was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2005 of the accrued pension benefits, based on a projection of the valuation at December 31, 2005, was estimated to be $5,355 million (2004 - $4,862 million). Pension plan assets available for these benefits were $4,713 million (2004 - $4,243 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2005, Hydro One Remote Communities charged $642 thousand (2004 - $498 thousand) of employee future benefits other than pension costs to results of operations and capitalized $131 thousand (2004 - $193 thousand) as part of the cost of fixed assets. Benefits paid by Hydro One Remote Communities were $342 thousand (2004 - $352 thousand). The liabilities, including the current portion, associated with employee future benefits other than pension for Hydro One Remote Communities at December 31, 2005 were $4,862 thousand (2004 - $4,432 thousand). A detailed description of employee future benefits is provided in Note 12 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2005.

12. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in thousands)	**2005**	**2004**
Environmental liabilities, January 1	8,829	10,370
Interest accretion	528	620
Expenditures	(1,238)	(2,161)
Revaluation adjustment	(694)	-
Environmental liabilities, December 31	7,425	8,829
Less: current portion	(2,322)	(1,625)
	5,103	7,204

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - $2,322 thousand; 2007 - $2,340 thousand; 2008 - $1,573 thousand; 2009 - $1,326 thousand; 2010 - $657 thousand; and thereafter - $nil.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. The Company continuously reviews factors affecting its cost estimates as well as environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates. As a result of its periodic review of future expenditure estimates in 2005, the Company revised downward its estimate of the future expenditures required to manage legacy environmental issues and reduced its environmental obligation and offsetting regulatory asset by $694 thousand.

13. SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares. No dividends were paid in 2005 or 2004. The Company does not expect to pay any future dividends under its breakeven business model.

14. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations to Ontario Hydro

The Province, OEFC, and the Independent Electricity System Operator (IESO) are related parties of Hydro One, and therefore, of Hydro One Remote Communities. In addition, the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One Remote Communities were as follows:

Hydro One Remote Communities receives amounts for remote rate protection from customer revenue collected by the IESO. Remote rate protection amounts received for the year ended December 31, 2005 were $21,108 thousand (2004 - $21,108 thousand), of which $20,617 thousand (2004 - $17,657 thousand) was recognized as revenue consistent with the breakeven business model. The balance of the remote rate protection amounts received totaled $491 thousand (2004 - $3,451 thousand). This amount has been allocated to the remote rate protection revenue variance, a regulatory liability account.

The provision for PILs was paid or payable to the OEFC.

Hydro One and Subsidiaries

Hydro One Remote Communities provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

Hydro One Remote Communities has service level agreements with Hydro One and its subsidiaries related to the provision of shared corporate functions such as legal, financial and human resources services, as well as operational services such as environmental, forestry and line services. In addition, Hydro One Remote Communities provided aboriginal relations support services to Hydro One Networks until April 2005. Operation, maintenance and administration costs include $1,535 thousand (2004 - $1,322 thousand) related to these services net of services provided by Hydro One Networks. The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in thousands)	**2005**	**2004**
Accounts receivable	252	279
Accounts payable	(40)	(36)

The long-term debt of the Company represents a note due to Hydro One. Financing charges include interest expense on this debt in the amount of $2,268 thousand (2004 - $1,787 thousand). Balances receivable or payable under the inter-company demand facility are due from or due to Hydro One. Financing charges include interest income on this facility in the amount of $268 thousand (2004 - $13 thousand expense).

15. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in thousands)	**2005**	**2004**
Accounts receivable decrease (increase)	1,441	(3,462)
Fuel, materials and supplies decrease (increase)	82	(345)
Long-term accounts receivable increase	(684)	-
Accounts payable and accrued charges (decrease) increase	(476)	1,086
Employee future benefits other than pension increase	431	234
Accrued interest decrease	(147)	-
Other	3	(57)
	650	(2,544)

16. CONTINGENCY

The transfer orders by which Hydro One Remote Communities acquired Ontario Hydro's remote communities business on April 1, 1999 did not result in a transfer of title to some generation and distribution assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. OEFC holds these assets.

Under the terms of Hydro One Remote Communities' transfer order, the Company is required to manage these assets until Hydro One Remote Communities has obtained all consents necessary to complete the transfer of title of these assets. If Hydro One Remote Communities cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time.

17. COMPARATIVE FIGURES

The comparative Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2005 Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2006

HYDRO ONE REMOTE COMMUNITIES INC.
AUDITORS' REPORT

To the Directors of
Hydro One Remote Communities Inc.:

We have audited the balance sheets of Hydro One Remote Communities Inc. as at December 31, 2006 and 2005 and the statements of operations, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Hydro One Remote Communities Inc. as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Toronto, Canada
April 18, 2007

Chartered Accountants
Licensed Public Accountants

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in thousands)	**2006**	**2005**
Revenues *(Note 14)*	38,520	34,411
Costs		
Operation, maintenance and administration *(Note 14)*	15,187	12,984
Fuel used for electric generation	18,608	15,289
Depreciation and amortization *(Note 3)*	3,980	4,032
	37,775	32,305
Income before financing charges and provision for payments in lieu of corporate income taxes	745	2,106
Financing charges *(Notes 4 and 14)*	1,329	1,917
(Loss) income before provision for payments in lieu of corporate income taxes	(584)	189
(Recovery of) provision for payments in lieu of corporate income taxes *(Notes 5 and 14)*	(584)	189
Net income	-	-

See accompanying notes to financial statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (Canadian dollars in thousands)	**2006**	**2005**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts - $761; 2005 - $533) *(Note 8 and 14)*	6,520	10,743
Fuel, materials and supplies	3,074	2,829
	9,594	13,572
Fixed assets *(Note 6)*		
Fixed assets in service	41,247	39,156
Less: accumulated depreciation	18,968	16,787
	22,279	22,369
Construction in progress	1,919	2,008
	24,198	24,377
Other long-term assets		
Regulatory assets *(Note 7)*	8,771	8,412
Long-term accounts receivable (net of allowance for doubtful accounts - $5,133; 2005 - $2,213) *(Note 8)*	3,654	684
Deferred debt costs	112	114
	12,537	9,210
Total assets	46,329	47,159
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 14)*	1,951	688
Accounts payable and accrued charges	7,082	7,511
Accrued interest	142	142
	9,175	8,341
Long-term debt *(Notes 9, 10 and 14)*	22,323	22,312
Other long-term liabilities		
Employee future benefits other than pension *(Note 11)*	5,318	4,563
Environmental liabilities *(Note 12)*	6,294	5,103
Regulatory liability *(Notes 7 and 14)*	3,219	6,840
	14,831	16,506
Total liabilities	46,329	47,159
Contingency *(Note 16)*		
Shareholder's equity		
Common shares (authorized: unlimited; issued 2) *(Note 13)*	-	-
Retained earnings	-	-
Total shareholder's equity	-	-
Total liabilities and shareholder's equity	46,329	47,159

See accompanying notes to financial statements.

On behalf of the Board:

Laura Formusa	Myles D'Arcey
Chair	Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in thousands)	**2006**	**2005**
Operating activities		
Net income	-	-
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	3,794	3,910
Remote rate protection revenue variance account	(3,621)	491
	173	4,401
Changes in non-cash balances related to operations *(Note 15)*	1,839	650
Net cash from operating activities	2,012	5,051
Investing activities		
Capital expenditures	(2,360)	(2,967)
Environmental expenditures *(Note 12)*	(915)	(1,238)
Net cash used in investing activities	(3,275)	(4,205)
Financing activities		
Termination of interest rate swap	-	(661)
Debt issuance costs	-	(114)
Other	-	(31)
Net cash used in financing activities	-	(806)
Net change in inter-company demand facility	(1,263)	40
Inter-company demand facility, January 1	(688)	(728)
Inter-company demand facility, December 31	(1,951)	(688)

See accompanying notes to financial statements.

1. DESCRIPTION OF BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). Hydro One Remote Communities owns and manages electricity supply assets in remote northern communities through 18 distribution systems that are not connected to Ontario's electricity transmission grid operated by Hydro One Networks Inc. (Hydro One Networks), also a wholly owned subsidiary of Hydro One. The Company's business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared using a cumulative breakeven business model and are for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2006 have been prepared and are publicly available.

Rate-setting

The Company's electricity generation and distribution business is subject to regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. The Company's regulatory assets primarily represent costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recognized a regulatory liability related to remote rate protection revenues received in excess of the amounts required to operate the Company on a cumulative breakeven basis, after tax. The Company's regulatory assets and regulatory liability recognized at December 31, 2006 are disclosed in Note 7.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liability into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition and the Remote Rate Protection Revenue Variance Account

Revenues attributable to the delivery of electricity are recognized at the time electricity is delivered to customers. The Company estimates the monthly revenue for the period based on customer history because customer meters are not generally read at the end of each month. These estimates are reconciled to actual customer consumption on a regular basis.

In approving electricity rates for a distributor that delivers electricity to remote customers, the OEB is required to provide rate protection for prescribed classes of customers by reducing the electricity rates that would otherwise apply in accordance with rules established pursuant to the *Ontario Energy Board Act, 1998*. Such remote rate protection amounts are collected by the Independent Electricity System Operator (IESO) through a charge to all Ontario customers. In 2002, *Ontario Regulation 442/01 – Rural or Remote Electricity Rate Protection* directed the method of developing the annual amount of rate protection and set the annual amount for 2002 and subsequent years at $21,108 thousand. On May 10, 2006, the OEB approved an amount of $21,097 thousand in rate protection for remote community customers.

Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operating result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Revenue Variance Account.

The balance in the Remote Rate Protection Revenue Variance Account is subject to future disposition by the OEB. On October 26, 2005, Hydro One Remote Communities made an application to the OEB to establish customer rates for 2006. The application also sought OEB approval to retain the balance in the Remote Rate Protection Revenue Variance Account for rate stabilization purposes. On May 10, 2006, the OEB approved this approach, and noted that the OEB will review this account for disposition on an ongoing basis.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). 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 Company provides for payments in lieu of corporate income taxes using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the Company's customers at that time.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by Hydro One Remote Communities to and from the pooled cash accounts. The Company earns interest on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of each month, less 0.02%. Hydro One Remote Communities is charged interest on overdraft inter-company balances based on the same banker's acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent spare parts and construction material for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction.

Some of the Company's generation and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Fixed assets in service consist of generation, distribution and administration and service assets. These asset categories are described below:

Generation

Generation assets are used in the generation of electricity and include hydroelectric equipment, wind turbines, diesel generators and tank farms.

Distribution

Distribution assets are used in the distribution of low-voltage electricity and include lines, poles, switches, transformers, protective devices and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2006 – 6.39%; 2005 – 6.80%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Generation	15 – 50	25
Distribution	15 – 55	40
Administration and service	5 – 50	43

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements, including those that arise as communities are connected to Hydro One Networks' transmission grid, are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Deferred Debt Costs

Deferred debt costs represent debt issuance costs allocated by Hydro One based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts, Premiums and Hedging

Discounts, premiums and hedging gains and losses allocated by Hydro One, based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue, are amortized over the period to the maturity of the related debt.

Employee Future Benefits

Employee future benefits provided by Hydro One Remote Communities include pension, group life insurance, health care and long-term disability.

In accordance with OEB rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Company has recognized a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from the estimates, including changes as a result of future decisions made by the OEB or the Province of Ontario (the Province).

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in thousands)	**2006**	**2005**
Depreciation of fixed assets in service	2,550	2,343
Fixed asset removal costs	186	122
Amortization of regulatory assets	1,244	1,567
	3,980	4,032

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in thousands)	**2006**	**2005**
Interest on long-term debt payable	1,237	2,268
Interest on inter-company demand facility	46	(268)
Less: Interest capitalized to construction in progress	(54)	(98)
Other	100	15
	1,329	1,917

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in thousands)	**2006**	**2005**
(Loss) income before provision for PILs	(584)	189
Federal and Ontario statutory income tax rate	36.12%	36.12%
(Recovery of) provision for PILs at statutory rate	(211)	68
(Decrease) increase resulting from:		
Net temporary differences:		
Remote rate protection revenue variance account	(1,309)	177
Depreciation and amortization in excess of capital cost allowance	690	649
Environmental expenditures	(330)	(447)
Employee future benefits other than pension expense in excess of cash payments	213	108
Interest capitalized for accounting purposes but deducted for tax purposes	(20)	(35)
Interest rate swap	4	(239)
Other	342	(172)
Net temporary differences	(410)	41
Net permanent differences:		
Large corporations tax	-	68
Other	37	12
Net permanent differences	37	80
(Recovery of) provision for PILs	(584)	189
Effective income tax rate	100.00%	100.00%

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax assets of $4,534 thousand (2005 - $5,411 thousand), based on substantively enacted tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized on an accrual basis rather than under the taxes payable method. As a result, the provision for PILs would have been higher by approximately $877 thousand.

6. FIXED ASSETS

December 31 (Canadian dollars in thousands)	Fixed Assets in Service	Accumulated Depreciation	Construction In Progress	Total
2006				
Generation	30,613	15,942	1,092	15,763
Distribution	5,409	1,392	285	4,302
Administration and service	5,225	1,634	542	4,133
	41,247	18,968	1,919	24,198
2005				
Generation	29,320	13,983	1,440	16,777
Distribution	5,180	1,258	88	4,010
Administration and service	4,656	1,546	480	3,590
	39,156	16,787	2,008	24,377

Financing costs are capitalized on fixed assets under construction, using the allowance for funds used during construction, and were $54 thousand in 2006 (2005 - $98 thousand).

7. REGULATORY ASSETS AND LIABILITY

Regulatory assets and liabilities can arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liability:

December 31 (Canadian dollars in thousands)	**2006**	**2005**
Regulatory assets:		
Employee future benefits other than pension	658	987
Environmental *(Note 12)*	8,113	7,425
Total regulatory assets	8,771	8,412
Regulatory liability:		
Remote rate protection revenue variance account	3,219	6,840

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose upon the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One Remote Communities recorded a regulatory asset in the original amount of $3,289 thousand to reflect this regulatory treatment. This regulatory asset has a remaining service life of 2 years (2005 – 3 years) and does not earn a return. In the absence of regulatory accounting, amortization expense in 2006 would have been lower by approximately $329 thousand (2005 - $329 thousand).

Environmental

The Company provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are recoverable through rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2011. In the absence of regulatory accounting, amortization expense in 2006 would have been lower and operation, maintenance and administration expense would have been higher by $915 thousand (2005 - $1,238 thousand).

Remote rate protection revenue variance account

The Company has recognized a long-term regulatory liability for remote rate protection amounts received in excess of amounts required to achieve an after-tax breakeven operating result. In the absence of regulatory accounting, revenue in 2006 would have been lower by $3,621 thousand (2005 - $491thousand higher).

8. LONG-TERM ACCOUNTS RECEIVABLE

During the year, $3,654 thousand (2005 - $684 thousand) in current accounts receivable, after inclusion of the related allowance for doubtful accounts, were reclassified from current assets to long-term, reflecting a change in payment terms for certain amounts and management judgment.

9. LONG-TERM DEBT

December 31 (Canadian dollars in thousands)	**2006**	**2005**
Long-term debt	23,000	23,000
Unamortized discount	(30)	(31)
Unamortized hedging loss	(647)	(657)
	22,323	22,312

Long-term debt represents a note issued on May 19, 2005 and payable to Hydro One. The note is denominated in Canadian dollars, bears interest at 5.38% and is due on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999. The original note, which bore interest at a rate of 7.77%, was issued as consideration for the purchase price of Hydro One Remote Communities' net assets.

The discount and hedge loss represent unamortized costs allocated by Hydro One to each of its subsidiaries, including Hydro One Remote Communities, on the basis of each subsidiary's proportionate share of Hydro One's related debt issue.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt is based on year-end quoted market prices for same or similar debt of the same remaining maturities, and is provided in the following table:

December 31 (Canadian dollars in thousands)	**2006**		**2005**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	23,000	24,132	23,000	24,668

1 The carrying amount of long-term debt represents the par value of the note.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2006, appropriate allowances had been made to reflect the risk of potential credit losses.

11. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for Society of Energy Professionals' represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, Hydro One contributed $86 million to its pension plan in respect of 2006 (2005 - $83 million), which will satisfy minimum funding requirements. Contributions are payable one month in arrears. A portion of these contributions are attributed to the Remote Communities business. Prior to 2004, Hydro One was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2006 of the accrued pension benefits, based on a projection of the valuation at December 31, 2006, was estimated to be $5,411 million (2005 - $5,355 million). Pension plan assets available for these benefits were $5,123 million (2005 - $4,713 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2006, Hydro One Remote Communities charged $813 thousand (2005 - $642 thousand) of employee future benefits other than pension costs to results of operations and capitalized $166 thousand (2005 - $131 thousand) as part of the cost of fixed assets. Benefits paid by Hydro One Remote Communities were $223 thousand (2005 - $342 thousand). The liabilities, including the current portion, associated with employee future benefits other than pension for Hydro One Remote Communities at December 31, 2006 were $5,618 thousand (2005 - $4,862 thousand).

A detailed description of employee future benefits is provided in Note 11 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2006.

12. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in thousands)	**2006**	**2005**
Environmental liabilities, January 1	7,425	8,829
Interest accretion	450	528
Expenditures	(915)	(1,238)
Revaluation adjustment	1,153	(694)
Environmental liabilities, December 31	8,113	7,425
Less: current portion	(1,819)	(2,322)
	6,294	5,103

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 - $1,819 thousand; 2008 - $2,076 thousand; 2009 - $2,177 thousand; 2010 - $1,575 thousand; 2011 - $1,481 thousand; and thereafter - $nil.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. The Company continuously reviews factors affecting its cost estimates as well as environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates. As a result of its periodic review of future expenditure estimates in 2006, the Company revised upward its estimate of the future expenditures required to manage legacy environmental issues and increased its environmental obligation and offsetting regulatory asset by $1,153 thousand.

13. SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares. The Company does not pay dividends under its breakeven business model.

14. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations to Ontario Hydro

The Province, OEFC, and the IESO are related parties of Hydro One, and therefore, of Hydro One Remote Communities. In addition, the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation, although as a self-financing and self-sufficient regulatory organization, it carries out independent regulation for Ontario's energy sector, including Hydro One's Remote Communities business. Transactions between these parties and Hydro One Remote Communities were as follows:

Hydro One Remote Communities receives amounts for remote rate protection from customer revenue collected by the IESO. Remote rate protection amounts received for the year ended December 31, 2006 were $21,102 thousand (2005 - $21,108 thousand). Consistent with the breakeven business model, $24,723 thousand was recognized as revenue in 2006 (2005 - $20,617 thousand). Revenue under the breakeven model exceeded amounts received by $3,621 thousand. In 2005, revenue was less than amounts received by $491 thousand. These differences were drawn from or charged to the remote rate protection revenue variance, a regulatory liability account.

The provision for PILs was paid or payable to the OEFC.

Hydro One and Subsidiaries

Hydro One Remote Communities provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

Hydro One Remote Communities has service level agreements with Hydro One and its subsidiaries related to the provision of shared corporate functions such as legal, financial and human resources services, as well as operational services such as environmental, forestry and line services. Operation, maintenance and administration costs include $1,759 thousand (2005 - $1,604 thousand) related to these services net of services provided by Hydro One Networks. The amounts due from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in thousands)	**2006**	**2005**
Accounts receivable	1,041	212

The long-term debt of the Company represents a note due to Hydro One. Financing charges include interest expense on this debt in the amount of $1,237 thousand (2005 - $2,268 thousand). Balances receivable or payable under the inter-company demand facility are due from or due to Hydro One. Financing charges include interest expense on this facility in the amount of $46 thousand (2005 - $268 thousand income).

15. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in thousands)	**2006**	**2005**
Accounts receivable decrease	4,223	1,509
Fuel, materials and supplies (increase) decrease	(245)	82
Long-term accounts receivable increase	(2,970)	(684)
Accounts payable and accrued charges increase (decrease)	74	(544)
Employee future benefits other than pension increase	756	431
Accrued interest decrease	-	(147)
Other	1	3
	1,839	650

16. CONTINGENCY

The transfer orders by which Hydro One Remote Communities acquired Ontario Hydro's remote communities business on April 1, 1999 did not result in a transfer of title to some generation and distribution assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. OEFC holds these assets.

Under the terms of Hydro One Remote Communities' transfer order, the Company is required to manage these assets until Hydro One Remote Communities has obtained all consents necessary to complete the transfer of title of these assets. If Hydro One Remote Communities cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time.

17. COMPARATIVE FIGURES

The comparative Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2006 Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2007

HYDRO ONE REMOTE COMMUNITIES INC.
AUDITORS' REPORT

To the Directors of
Hydro One Remote Communities Inc.:

We have audited the Balance Sheets of Hydro One Remote Communities Inc. as at December 31, 2007 and 2006 and the Statements of Operations and Cash Flows for the years then ended. These financial statements are the responsibility of management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Hydro One Remote Communities Inc. as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants
Licensed Public Accountants
Toronto, Canada
April 23, 2008

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in thousands)	**2007**	**2006**
Revenues *(Note 13)*	36,672	38,520
Costs		
Operation, maintenance and administration *(Note 13)*	12,636	15,187
Fuel used for electric generation	19,319	18,608
Depreciation and amortization *(Note 3)*	4,002	3,980
	35,957	37,775
Income before financing charges and provision for payments in lieu of corporate income taxes	715	745
Financing charges *(Notes 4 and 13)*	1,142	1,329
Loss before provision for payments in lieu of corporate income taxes	(427)	(584)
Recovery of payments in lieu of corporate income taxes *(Notes 5 and 13)*	(427)	(584)
Net income	-	-
Other comprehensive income	9	-
Comprehensive income	9	-

See accompanying notes to financial statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (Canadian dollars in thousands)	**2007**	**2006**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts - $745; 2006 - $761) *(Note 13)*	6,522	6,687
Fuel, materials and supplies	3,641	3,074
Regulatory assets *(Note 7)*	1,806	1,819
	11,969	11,580
Fixed assets *(Note 6)*		
Fixed assets in service	43,390	41,247
Less: accumulated depreciation	20,409	18,968
	22,981	22,279
Construction in progress	2,517	1,919
	25,498	24,198
Other long-term assets		
Regulatory assets *(Note 7)*	8,521	6,952
Long-term accounts receivable (net of allowance for doubtful accounts - $4,788; 2006 - $5,133)	2,235	3,654
	10,756	10,606
Total assets	48,223	46,384
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 13)*	1,474	2,078
Accounts payable and accrued charges	8,787	7,122
Accrued interest	142	142
	10,403	9,342
Long-term debt *(Notes 8, 9 and 13)*	22,860	22,211
Other long-term liabilities		
Employee future benefits other than pension *(Note 10)*	5,941	5,318
Environmental liabilities *(Note 11)*	8,192	6,294
Regulatory liability *(Notes 7 and 13)*	1,464	3,219
	15,597	14,831
Total liabilities	48,860	46,384
Contingency *(Note 15)*		
Shareholder's equity		
Common shares (authorized: unlimited; issued 2) *(Note 12)*	-	-
Retained earnings	-	-
Accumulated other comprehensive income	(637)	-
Total shareholder's equity	(637)	-
Total liabilities and shareholder's equity	48,223	46,384

See accompanying notes to financial statements.

On behalf of the Board:

Laura Formusa
Chair

Myles D'Arcey
Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in thousands)	**2007**	**2006**
Operating activities		
Net income	-	-
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	3,799	3,794
Remote rate protection revenue variance account	(1,755)	(3,621)
Environmental expenditures	(983)	(915)
	1,061	(742)
Changes in non-cash balances related to operations *(Note 14)*	3,289	1,712
Net cash from operating activities	4,350	970
Investing activities		
Capital expenditures	(3,755)	(2,360)
Net cash used in investing activities	(3,755)	(2,360)
Financing activities		
Hedge losses	9	-
Net cash from financing activities	9	-
Net change in inter-company demand facility	604	(1,390)
Inter-company demand facility, January 1	(2,078)	(688)
Inter-company demand facility, December 31	(1,474)	(2,078)

See accompanying notes to financial statements.

1. DESCRIPTION OF BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). Hydro One Remote Communities owns and manages electricity supply assets in remote northern communities through 18 distribution systems that are not connected to Ontario's electricity transmission grid which is operated by Hydro One Networks Inc. (Hydro One Networks), also a wholly owned subsidiary of Hydro One. The Company's business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared using a cumulative breakeven business model and are for the specific use of the OEB. Certain amounts presented in these financial statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2007 have been prepared and are publicly available.

Rate-setting

The Company's electricity generation and distribution business is subject to regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. The Company's regulatory assets primarily represent costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recognized a regulatory liability related to remote rate protection revenues received in excess of the amounts required to operate the Company on a cumulative breakeven basis, after payments in lieu of corporate income taxes (PILs). The Company's regulatory assets and regulatory liability recorded at December 31, 2007 are disclosed in Note 7.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liability into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations for the period when the assessment is made.

Revenue Recognition and the Remote Rate Protection Revenue Variance Account

Revenues attributable to the delivery of electricity are recognized at the time electricity is delivered to customers.

In approving electricity rates for a distributor that delivers electricity to remote customers, the OEB is required to provide rate protection for prescribed classes of customers by reducing the electricity rates that would otherwise apply in accordance with rules established pursuant to the *Ontario Energy Board Act, 1998*. Such remote rate protection amounts are collected by the Independent Electricity System Operator (IESO) through a charge to all Ontario customers. In 2002, *Ontario Regulation 442/01 – Rural or Remote Electricity Rate Protection* directed the method of developing the annual amount of rate protection and set the annual amount for 2002 and subsequent years at $21,108 thousand. On May 10, 2006, the OEB approved an amount of $21,097 thousand for rate protection for remote community customers.

Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve breakeven results of operations, after the inclusion of PILs. Any excess or deficiency in remote rate protection revenues necessary to lead to breakeven results of operations is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account.

The balance in the RRPR variance account is subject to future disposition by the OEB. On October 26, 2005, Hydro One Remote Communities made an application to the OEB to establish customer rates for 2006. The application also sought OEB approval to retain the balance in the RRPR variance account for rate stabilization purposes. On May 10, 2006, the OEB approved this approach, and noted that it will review this account for disposition on an ongoing basis. Hydro One Remote Communities plans to file a forward test year application with the OEB by August 15, 2008 for rates to become effective May 1, 2009.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to make payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation (OEFC). 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 Company provides for PILs using the taxes payable method, as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the Company's customers at that time.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by Hydro One Remote Communities to and from the pooled cash accounts. The Company earns interest on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of each month, less 0.02%. Hydro One Remote Communities is charged interest on overdraft inter-company balances based on the same banker's acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent spare parts and construction material for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction.

Some of the Company's generation and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Fixed assets in service consist of generation, distribution and administration and service assets. These asset categories are described below:

Generation

Generation assets are used in the generation of electricity and include hydroelectric equipment, wind turbines, diesel generators and tank farms.

Distribution

Distribution assets are used in the distribution of low-voltage electricity and include lines, poles, switches, transformers, protective devices and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2007 – 4.95%; 2006 – 6.39%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review by the OEB. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $95 thousand per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Generation	1% - 13%	7%
Distribution	1% - 10%	3%
Administration and service	3% -20%	4%

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Financial Instruments

Effective January 1, 2007, the Company adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative financial statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date. The impact of this amortization is immaterial to the Statement of Operations.

Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the consolidated balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Long-term accounts receivable	Loans and receivables
Inter-company demand facility	Other liabilities
Long-term debt	Other liabilities

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

Hydro One periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis and are allocated to Hydro One subsidiaries and their regulated businesses. Hydro One does not engage in derivative trading or speculative activities.

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to accumulated other comprehensive income. The hedging losses are amortized to financing charges through OCI using the effective interest method over the term of the hedged debt.

Transaction Costs

Transaction costs based on Hydro One Remote Communities' proportionate share of the relevant Hydro One transaction, for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability. Transaction costs are amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization method from an annuity basis to the effective interest method was not material.

Discounts and Premiums

Discounts, premiums allocated by Hydro One based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue, are amortized over the period of the related debt using the effective interest method.

Employee Future Benefits

Employee future benefits provided by Hydro One Remote Communities include pension, group life insurance, health care and long-term disability.

In accordance with OEB rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Company recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from the estimates, including changes as a result of future decisions made by the OEB or the Province of Ontario (the Province).

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in thousands)	**2007**	**2006**
Depreciation of fixed assets in service	2,486	2,550
Fixed asset removal costs	204	186
Amortization of regulatory assets	1,312	1,244
	4,002	3,980

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in thousands)	**2007**	**2006**
Interest on long-term debt payable	1,237	1,237
Interest on inter-company demand facility	74	46
Less: Interest capitalized on construction in progress	(113)	(54)
Other	(56)	100
	1,142	1,329

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in thousands)	**2007**	**2006**
Loss before provision for PILs	(427)	(584)
Federal and Ontario statutory income tax rate	36.12%	36.12%
Recovery of PILs at statutory rate	(154)	(211)
(Decrease) increase resulting from:		
Net temporary differences:		
Depreciation and amortization in excess of capital cost allowance	659	1,105
RRPR variance account	(634)	(1,309)
Environmental expenditures	(355)	(330)
Employee future benefits other than pension expense in excess of cash payments	172	213
Overhead capitalized for accounting purposes but deducted for tax purposes	(75)	(65)
Interest capitalized for accounting purposes but deducted for tax purposes	(41)	(20)
Other	(36)	(4)
Net temporary differences	(310)	(410)
Net permanent differences:	37	37
Recovery of PILs	(427)	(584)
Effective income tax rate	100.00%	100.00%

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax assets of $3,946 thousand (2006 - $4,534 thousand), based on substantively enacted tax rates, have not been recorded. In the absence of rate regulated accounting, the Company’s provision for PILs would have been recognized using the liability method rather than under the taxes payable method. As a result, the provision for PILs would have been higher by approximately $588 thousand (2006 - $877 thousand), including the impact of substantively enacted tax rates.

6. FIXED ASSETS

December 31 (Canadian dollars in thousands)	Fixed Assets in Service	Accumulated Depreciation	Construction In Progress	Total
2007				
Generation	32,128	17,952	2,341	16,517
Distribution	5,307	1,207	121	4,221
Administration and service	5,955	1,250	55	4,760
	43,390	20,409	2,517	25,498
2006				
Generation	30,613	15,942	1,092	15,763
Distribution	5,409	1,392	285	4,302
Administration and service	5,225	1,634	542	4,133
	41,247	18,968	1,919	24,198

Financing costs are capitalized on fixed assets under construction, using the OEB's approved allowance for funds used during construction, and were $113 thousand in 2007 (2006 - $54 thousand).

7. REGULATORY ASSETS AND LIABILITY

Regulatory assets and liabilities can arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liability:

December 31 (Canadian dollars in thousands)	**2007**	**2006**
Regulatory assets:		
Environmental *(Note 11)*	9,998	8,113
Employee future benefits other than pension	329	658
Total regulatory assets	10,327	8,771
Less: current portion	1,806	1,819
	8,521	6,952
Regulatory liability:		
RRPR variance account	1,464	3,219

Environmental

The Company records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2015 (2006 – 2011). In the absence of regulatory accounting, amortization expense in 2007 would have been lower by $983 thousand (2006 - $915 thousand).

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose upon the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One Remote Communities recorded a regulatory asset in the original amount of $3,289 thousand to reflect this regulatory treatment. This regulatory asset has a remaining service life of 1 year (2006 – 2 years) and does not earn a return. In the absence of regulatory accounting, amortization expense in 2007 would have been lower by approximately $329 thousand (2006 - $329 thousand).

RRPR variance account

The Company has recognized a long-term regulatory liability for remote rate protection amounts received in excess of amounts required to achieve a breakeven results of operations, after consideration of PILs. In the absence of regulatory accounting, revenue in 2007 would have been lower by $1,755 thousand (2006 - $3,621 thousand).

8. LONG-TERM DEBT

December 31 (Canadian dollars in thousands)	**2007**	**2006**
Long-term debt	23,000	23,000
Net unamortized debt discount	(30)	(30)
Unamortized hedging loss [1]	-	(647)
Unamortized debt issuance costs	(110)	(112)
	22,860	22,211

[1] Unamortized net losses relating to Hydro One Remote Communities' share of Hydro One's settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Long-term debt represents a note issued on May 19, 2005 and payable to Hydro One. The note is denominated in Canadian dollars, bears interest at 5.38% and is due on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets.

The debt discount and hedging loss represent unamortized costs allocated by Hydro One to each of its subsidiaries, including Hydro One Remote Communities, on the basis of each subsidiary's proportionate share of Hydro One's related debt issues.

9. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt is based on year-end quoted market prices for same or similar debt of the same remaining maturities, and is provided in the following table:

December 31 (Canadian dollars in thousands)	**2007**		**2006**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	23,000	23,106	23,000	24,132

1 The carrying amount of long-term debt represents the par value of the note.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Sufficient allowances have been recorded to reflect the risk of potential credit losses.

10. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 20, 2007, effective for December 31, 2006, Hydro One contributed $95 million to its pension plan in respect of 2007 (2006 - $86 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2007 of the accrued pension benefits, based on a projection of the valuation at December 31, 2007, was estimated to be $5,077 million (2006 - $5,411 million). Pension plan assets available for these benefits were $5,100 million (2006 - $5,123 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2007, Hydro One Remote Communities charged $660 thousand (2006 - $813 thousand) of employee future benefits other than pension costs to results of operations and capitalized $204 thousand (2006 - $166 thousand) as part of the cost of fixed assets. Benefits paid by Hydro One Remote Communities were $236 thousand (2006 - $223 thousand). The liabilities, including the current portion, associated with employee future benefits other than pension for Hydro One Remote Communities at December 31, 2007 were $6,241 thousand (2006 - $5,618 thousand).

A detailed description of employee future benefits is provided in Note 10 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2007.

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in thousands)	**2007**	**2006**
Environmental liabilities, January 1	8,113	7,425
Interest accretion	484	450
Expenditures	(983)	(915)
Revaluation adjustment	2,384	1,153
Environmental liabilities, December 31	9,998	8,113
Less: current portion	(1,806)	(1,819)
	8,192	6,294

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 - $1,806 thousand; 2009 - $1,685 thousand; 2010 - $1,981 thousand; 2011 - $1,843 thousand; 2012 - $1,137 thousand; and thereafter - $2,937 thousand.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. The Company continuously reviews factors affecting its cost estimates as well as environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates. As a result of its periodic review of future expenditure estimates and the duration of its planned work program, in 2007 the Company increased its estimate of the future expenditures required to manage legacy environmental issues and increased its environmental obligation and offsetting regulatory asset by $2,384 thousand (2006 - $1,153 thousand).

12. SHARE CAPITAL

The Company is authorized to issue an unlimited number of common shares. The Company does not pay dividends under its breakeven business model.

13. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations to Ontario Hydro

The Province, the OEFC, and the IESO are related parties of Hydro One, and therefore, of Hydro One Remote Communities. In addition, the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation, although as a self-financing and self-sufficient regulatory organization, it carries out independent regulation for Ontario's energy sector, including Hydro One's Remote Communities business. Transactions between these parties and Hydro One Remote Communities were as follows:

Hydro One Remote Communities receives amounts for remote rate protection from customer revenue collected by the IESO. Remote rate protection amounts received for the year ended December 31, 2007 were $21,097 thousand (2006 - $21,102 thousand). Consistent with the breakeven business model, $22,852 thousand was recognized as revenue in 2007 (2006 - $24,723 thousand). Revenue under the breakeven business model exceeded amounts received by $1,755 thousand (2006 - $3,621 thousand). These amounts were drawn from the remote rate protection revenue variance, a regulatory liability account.

The provision for PILs was paid or payable to the OEFC.

Hydro One and Subsidiaries

Hydro One Remote Communities provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

Hydro One Remote Communities has service level agreements with Hydro One and its subsidiaries related to the provision of shared corporate functions such as legal, financial and human resources services, as well as operational services such as environmental, forestry and line services. Operation, maintenance and administration costs include $1,586 thousand (2006 - $1,759 thousand) related to these services provided by Hydro One Networks. The amounts due from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in thousands)	**2007**	**2006**
Accounts receivable	1,617	1,208

The long-term debt of the Company represents a note due to Hydro One. Financing charges include interest expense on this debt in the amount of $1,237 thousand (2006 - $1,237 thousand). Balances receivable or payable under the inter-company demand facility are due from or due to Hydro One. Financing charges include interest expense on this facility in the amount of $74 thousand (2006 - $46 thousand).

14. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in thousands)	**2007**	**2006**
Accounts receivable decrease	165	4,056
Fuel, materials and supplies increase	(567)	(245)
Long-term accounts receivable decrease (increase)	1,419	(2,970)
Accounts payable and accrued charges increase	1,678	114
Employee future benefits other than pension increase	623	756
Other	(29)	1
	3,289	1,712

15. CONTINGENCY

The transfer orders by which Hydro One Remote Communities acquired Ontario Hydro's remote communities business on April 1, 1999 did not result in a transfer of title to some generation and distribution assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, OEFC holds these assets.

Under the terms of the transfer order, the Company is required to manage these assets until the Company has obtained all consents necessary to complete the transfer of title of these assets to the Company. If the Company cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time.

16. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2007 financial statements.

HYDRO ONE INC. – ANNUAL REPORTS (2005, 2006 and 2007)

Included in this exhibit are the Historic Years Annual Reports

Attachment 1: Annual Report 2005
Attachment 2: Annual Report 2006
Attachment 3: Annual Report 2007

hydro One




We start every day with 100 years of experience

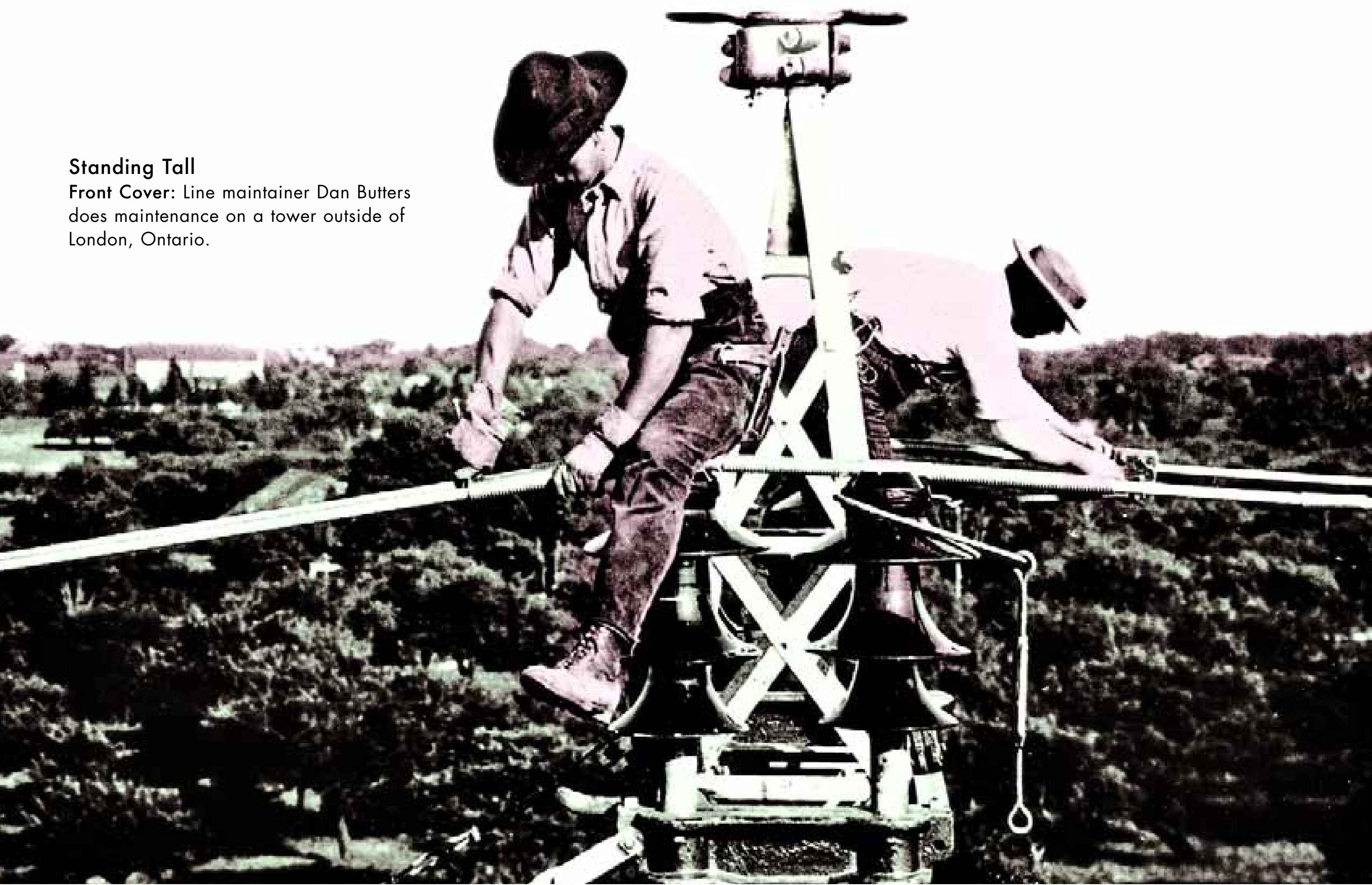
2005 Annual Report

1906–2005

Powering Ontario for 100 years.

Table of Contents

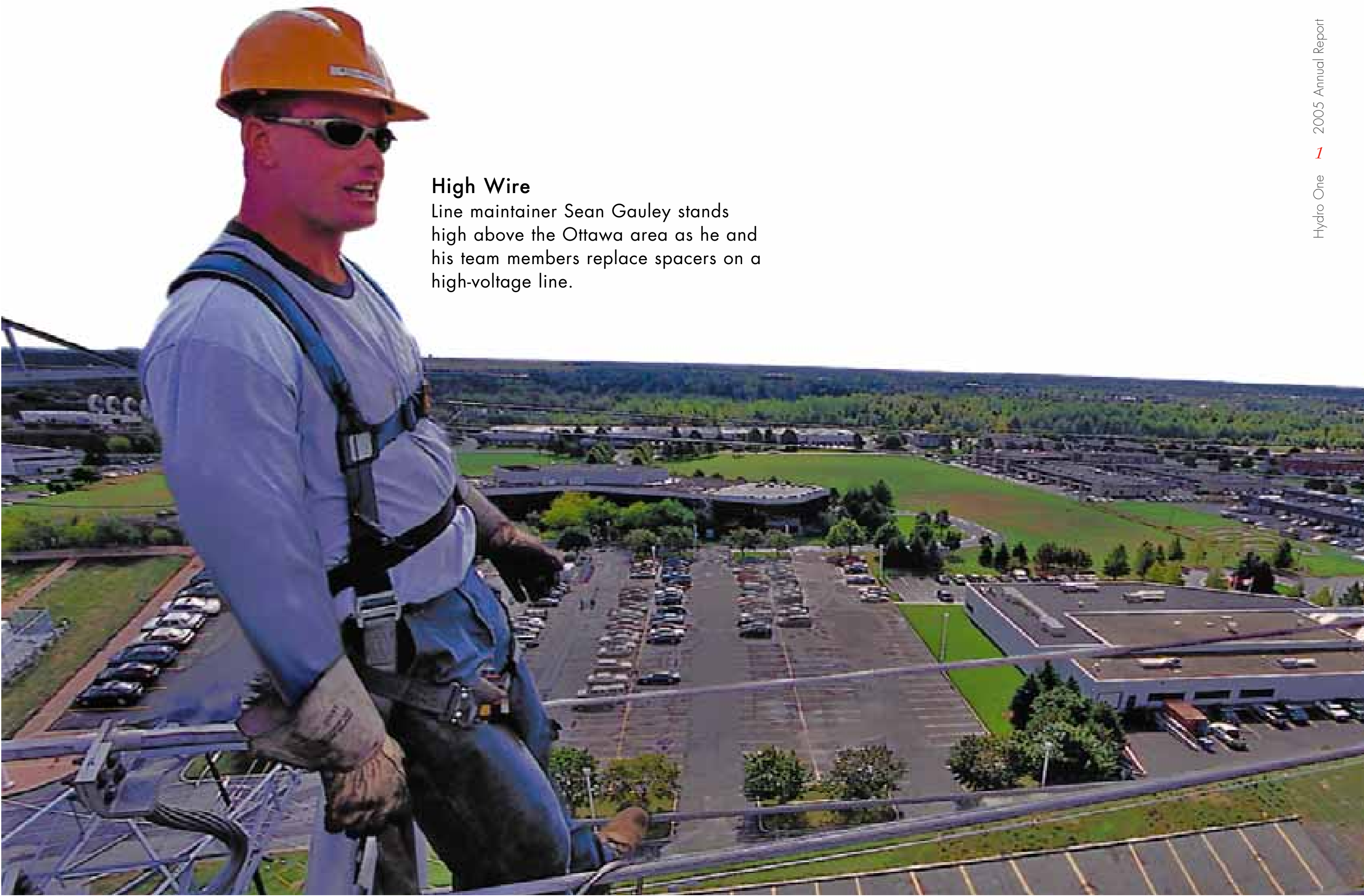
Standing Tall
Front Cover: Line maintainer Dan Butters does maintenance on a tower outside of London, Ontario.



Safety *Service* Reliability *Pride* Value

At the flick of a switch electricity arrives safely and reliably in your homes. It powers your businesses and helps you keep them growing. Our job is to take care of the system that enables electricity to flow to you, no matter where you live in Ontario. We work to make sure this vital resource is there when you need it. With your help, we're ensuring Ontario gets the most out of its electricity system.

We do this by focusing on our five values.



High Wire
Line maintainer Sean Gauley stands high above the Ottawa area as he and his team members replace spacers on a high-voltage line.

— Hydro One at a Glance —

Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom. The subsidiaries are necessary to meet legislative and regulatory requirements.

Hydro One Networks Inc.
Represents the significant majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Inc.
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 km outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 18 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our fibre optic capacity to business customers and represents less than 1 per cent of our total assets.

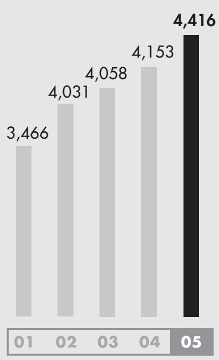
— *Accomplishments in 2005* —

- Completed the Parkway transformer station on time and budget. This facility improves the reliability of the transmission system serving the electricity demand in the Greater Toronto Area (GTA) and helped facilitate the shut down of the Lakeview generating station.
- To better serve Canada's largest city, we began construction of two underground cable circuits to reinforce our electricity transmission facilities in downtown Toronto.
- To improve reliability and supply in southern Ontario, we started construction of a new 76-kilometre 230-kV line in the Niagara region.
- To secure necessary rates for future distribution work programs investments and system costs, Hydro One prepared and filed evidence with the Ontario Energy Board (OEB).
- Significantly improved or maintained customer satisfaction across all of our customer segments.
- Improved efficiency through an increasingly flexible workforce which is reflected in our strong financial results and our ability to achieve more for our customers and the people of Ontario.

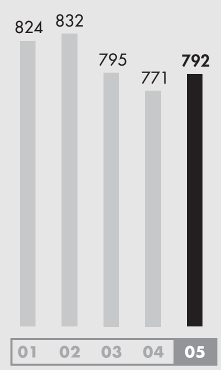
— *Key Credit Strengths* —

- Hydro One owns and operates the largest electricity delivery system in Ontario and one of the largest in North America
- Experienced management team focused on the core electricity delivery business
- Highly skilled and experienced workforce with first-class operating systems
- Recognized industry leader in the development and implementation of a safe workplace
- A track record of stable and predictable earnings from our regulated transmission and distribution businesses
- Conservative capital structure and strong cash flow performance

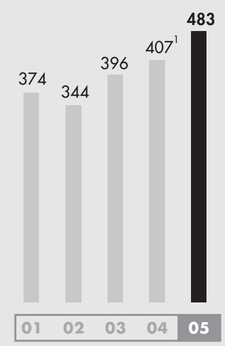
Year ended December 31 (Canadian dollars in millions)	**2005**	2004	**$ Change**	**% Change**
Revenues	**4,416**	4,153	**263**	**6**
Purchased power	**2,131**	1,987	**144**	**7**
Operating costs	**1,279**	1,251	**28**	**2**
Net income	**483**	407[1,2]	**76**[2]	**19**[2]
Net cash from operations	**1,170**	911	**259**	**28**
Statistics				
Transmission – units transmitted *(TWh)*[3]	**157.0**	153.4	**3.6**	**2**
Average Ontario 60-minute peak demand *(MW)*[3]	**23,074**	22,375	**699**	**3**
Distribution – units distributed to Hydro One customers *(TWh)*[3]	**29.7**	28.5	**1.2**	**4**



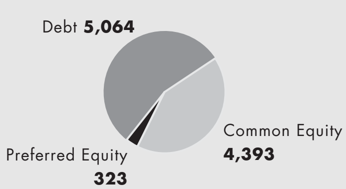
Revenues
Year ended December 31
(Cdn $ millions)



Operation, Maintenance and Administration Costs
Year ended December 31
(Cdn $ millions)

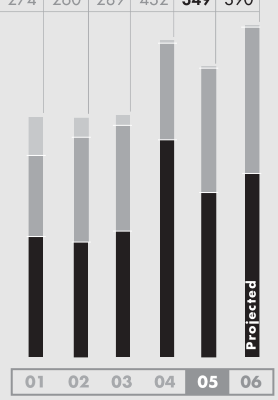


Net Income
Year ended December 31
(Cdn $ millions)



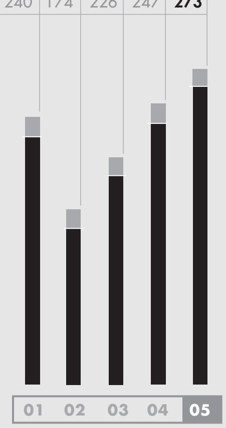
Capital Structure
December 31, 2005
(Cdn $ millions)

	01	02	03	04	05	06
Other	45	24	16	7	**4**	5
Distribution	247	286	292	288	**338**	360
Transmission	274	260	289	432	**349**	390



Capital Expenditure
Year ended December 31
(Cdn $ millions)

	01	02	03	04	05
Preferred	18	18	18	18	**18**
Common	240	174	226	247	**273**



Dividends
Year ended December 31
(Cdn $ millions)

[1] Net income for 2004 was $498 million, including a one-time regulatory recovery of $91 million.

[2] Based on 2004 net income of $498 million, which includes a one-time regulatory recovery of $91 million, 2005 net income was lower by $15 million, or 3%.

[3] System-related statistics include preliminary figures for December.

The Company's excellent results reflect Hydro One's continued commitment to transparent, prudent management of this vital provincial asset.

In 2005, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, skillfully navigating the operational challenges posed by one of the hottest summers on record that set new record peaks for demand. Hydro One's previous investments in its system paid off and the Company embarked on several large projects to ensure reliable supply for the people of Ontario.

In 2005, Hydro One continued its track record of strong financial performance. The Company's net income in 2005 increased $76 million, or 19%, to $483 million compared to 2004, putting aside the impact of last year's one-time regulatory recovery. This increase primarily reflects higher revenues within our transmission and distribution businesses, including the impact of the summer's record heat. During the heat wave, Hydro One maintained an intense focus on its operations over the summer months to ensure the reliable delivery of electricity across the province.

As Chair of Hydro One, it's my role to ensure that the Company operates in a transparent, accountable and responsible way. Hydro One conforms to the highest standards of corporate governance in our relationship with our shareholder and in the fulfillment of our fiduciary responsibilities as a Board. The Board of Directors in 2005 was highly engaged, ensuring Hydro One remains focused on maintaining a strong, fiscally responsible and reliable electricity system that meets today's needs and is prepared for the challenges that lay ahead. This year, Hydro One focused on new securities regulations and is well positioned to meet these new requirements set out by the Ontario Securities Commission.

The Company's excellent results reflect Hydro One's ongoing commitment to the transparent, strong and focused leadership of our CEO, Tom Parkinson and our ongoing commitment to prudent management of this vital provincial asset. Hydro One made critical investments both in transmission and distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Total capital and operation, maintenance and administrative expenditures for 2005 were $1,483 million. In addition, Hydro One paid its shareholder, the Province of Ontario, dividends of $291 million, and recorded $198 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province. The Board expects continued strong, stable financial performance.

I would like to take this opportunity to express my thanks to the Board members for their contribution and dedication. I would also like to especially thank retiring Board members Geoffrey Beattie, Adam Zimmerman and Dr. Murray Frum. As directors, each of them made outstanding contributions to the continued success of Hydro One.

On behalf of the Board of Directors, I would like to thank all of Hydro One's people for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.

R. Burak

Rita Burak
Chair, Hydro One Inc.

Our goal is to be the best transmission and distribution business in North America.

We start every day with 100 years of experience.

I look at the black and white photographs on the walls of our boardroom and I see a proud history. Using draught horses, steam power and raw force of will, the people of Hydro Electric Power Commission (H.E.P.C.) connected the power of Niagara Falls to Ontario communities. Those first transmission lines brought more than electricity. They brought prosperity. They brought a higher standard of living. They brought a better future. The power delivery system that gradually spread to connect almost every community in Ontario meant that Ontario businesses, communities and families have prospered and grown in the last century. Today we continue that work. We deliver the electricity that is the very lifeblood of Ontario's economy.

In 2005, we worked hard to integrate new sources of generation into the system. We've begun construction of our Niagara Reinforcement Project to upgrade the transmission line that delivers the power produced in Niagara Falls to the rest of Southern Ontario. By upgrading this line, we will be able to deliver an additional 800 MW of electricity to where it needs to be. The new Parkway transformer station in the GTA was completed on time and on budget, safely facilitating the decommissioning of the coal-fired Lakeview generating station. Work has also begun on an underground cable in downtown Toronto to improve supply flexibility to Canada's largest city.

In 2005, Hydro One faced one of the hottest summers on record. With 45 days with temperatures above 30 degrees, the aging transmission system was stretched to its very capacity. But it held. It held because we've invested wisely in our systems over the years. It held because our team knows how to get the very most out of Ontario's electricity highway. While I'm proud that our system and our people were able to meet the challenges of the summer, I also believe that as demand increases we need to find better ways of doing things. Part of the answer will be found in working with our customers to find conservation solutions that work. In 2005, we had some success with conservation pilot projects and in 2006 we are looking to achieve more.

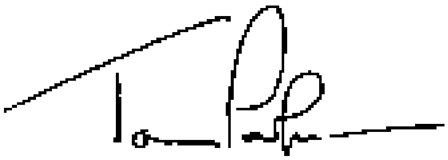
2005 was a dynamic year for our company. Hydro One earned a profit of $483 million and we paid our shareholder, the Province of Ontario an excellent dividend. We remain committed to earning a healthy return for our shareholder while ensuring Ontario's electricity delivery

system can continue to perform at an optimal level long into the future. Our stable and strong financial results this year were consistent with our expectations.

By 2010, our goal is to be the best transmission and distribution business in North America. What does this mean? We want to have the best safety record in the world, with zero serious injuries and zero serious near misses. We have top quartile reliability in transmission and are working towards the same in distribution when compared against similar utilities. Customer satisfaction, where major gains have been made in the last two years, is targeted to reach 90 per cent across all segments. We will continue to deliver shareholder value through fair transmision and distribution rates, prudent expenditures, employee productivity improvements and excellent operating efficiency.

Stable and strong are not euphemisms for static or stationary. The electricity industry, after 100 years of rich history in Ontario, is possibly at one of its most critical junctures. New transmission facilities are needed to facilitate the delivery of new supply to customers, to reduce constraints on the system, and improve our ability to import electricity. Only by improving cooperation and coordination between communities, regulators and industry partners can we continue to reliably deliver the electricity that Ontario depends upon. Only by realizing that we are all working towards the same goal – safe reliable electricity and continued prosperity for Ontarians – can we move quickly enough to put the necessary and proper assets in place.

I'd like to thank the people of Hydro One for their commitment to our strategic direction, and for the fantastic job they do everyday. It shows in our results and in the satisfaction of our customers. Much has changed in the last century. We do things differently, we use different tools and we work much more safely. But one thing has not changed. We continue to focus on providing the people of Ontario with an electricity delivery system that allows them to prosper now and long into the future.



Tom Parkinson
President and Chief Executive Officer, Hydro One Inc.

Connecting Ontario

Left: Stringing the first transmission lines on steel towers to connect the Niagara area to southern Ontario communities. February, 1910.

Broad Shoulders

Above: Hydro One's high-voltage system includes more than 28,000 circuit kilometres of lines supported by nearly 48,000 towers all over Ontario. In 2005, work was started to upgrade 76 km of line to allow more electricity to flow from the Niagara region.

"We are off now, just let anyone try and stop us."

With that sentence, Sir Adam Beck opened the Wasdell Falls generating station. Beck, also known as the father of Ontario's electricity system, had a vision that electricity was the way to a bright future for everyone in Ontario. He pushed for the construction of generating stations to produce electricity on a massive scale.

But it wasn't enough to just produce power. Beck believed that only by delivering power to all parts of Ontario would everyone share in the economic prosperity that electricity brings.

He oversaw the development of a network of transmission and distribution lines that has now grown to stretch more than 150,000 kilometres across all parts of Ontario.

His vision and energy helped make Ontario the economic engine of Canada. Without electricity, our world would be a very different place. Hydro One continues to focus on delivering electricity and economic prosperity to the people of Ontario.

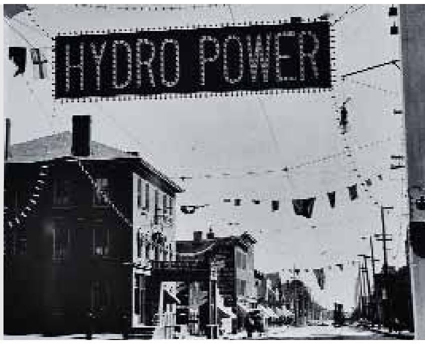
1906
The Hydro-Electric Power Commission is created to build transmission lines to carry power generated at Niagara Falls. Adam Beck, is named chairman.

1910
The first 110,000-volt electric power lines deliver electricity to municipalities in southwestern Ontario, starting with Kitchener (then known as Berlin).

1912
The Beck Electric Circus tours the countryside showcasing the wonders of electricity.

Left: From the very early days, London was at the forefront in promoting hydro, as demonstrated by this photograph taken on the occasion of the Labour Parade in that city on September 1, 1913.

Right: This is a close-up of one of the displays that formed part of the colourful decorations in Kitchener on October 11, 1910, marking the first time power was switched on in that community.



1922
What would come to be known as the Sir Adam Beck 1 generation site on the Niagara River goes into service. At completion it's the largest generation facility in the world, requiring five times the excavation of the largest of the Great Pyramids.

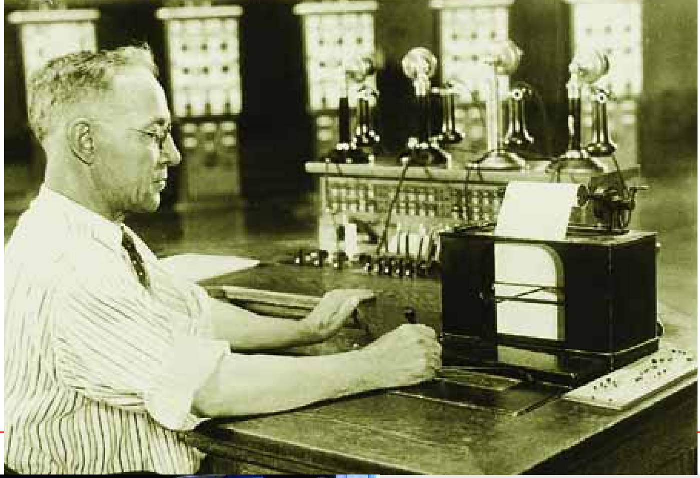
Wiring Ontario for Delivery
Right: Workers at an early distribution station ready the wiring for commissioning. In the early days of building Ontario's electricity system, building and commissioning equipment was a major part of Ontario Hydro's work.

Making Connections
Below right: Leaside transformer station in Toronto is a major hub in our electricity delivery system. Transformer stations not only convert high-voltage electricity to lower voltages, they also expedite the delivery of electricity between stations.

building reliability

In the first 70 years of its existence, Ontario's electricity company focused as much on new construction to keep up with growing demand as it did on the actual business of generating and delivering electricity.

While we're solidly focused on operating and maintaining our transmission and distribution assets, we are now entering a phase that will bring much more new construction. In 2005, Hydro One invested more than $700 million in upgrades, construction and maintenance for our transmission network. With the lengthy approval process for new construction, we are often working with our customers and industry partners to plan our work schedule years in advance.



Power People

Left and above: Highly skilled professionals, like Cathy Freskiw, are at the heart of Hydro One's system. Even though the equipment has changed a great deal, our commitment to delivering a reliable supply of electricity to the people of Ontario has not.

Taking Care of Distribution

In 2005, we increased our capital investments in our distribution system by $50 million over 2004, from $288 million to $338 million.

This includes investment in new mechanical brushing equipment that will greatly enhance our ability to keep our distribution rights-of-way clear. Better brushing techniques will translate directly into improved service and productivity by decreasing the number of outages and allowing our crews easier access to remote equipment.

Pole replacement projects targeting communities across the province, from Kemptville to Moosonee, replaced 3,600 poles nearing the end of their service life. This work will continue in 2006 and beyond to ensure ongoing reliable supply to our approximately 1.3 million Hydro One distribution customers.

Niagara *Reinforcement* Project

In 1910, the power of Niagara Falls was first connected to Ontario's electricity consumers along the province's first transmission lines. Those first lines delivered more than electricity. They delivered a new way of living, working and doing business. They changed our world.

This year, we began a major upgrade of transmission facilities so that even more of the Falls' awesome power can reach Ontario's homes and businesses by the summer of 2006. Engineering and construction crews are taking down an old 115 kV line and replacing it with a new 230 kV double-circuit line across 76 kilometres. This project will allow us to deliver 800 MW more power – enough for 300,000 homes – from the Niagara Falls area to where it needs to be.

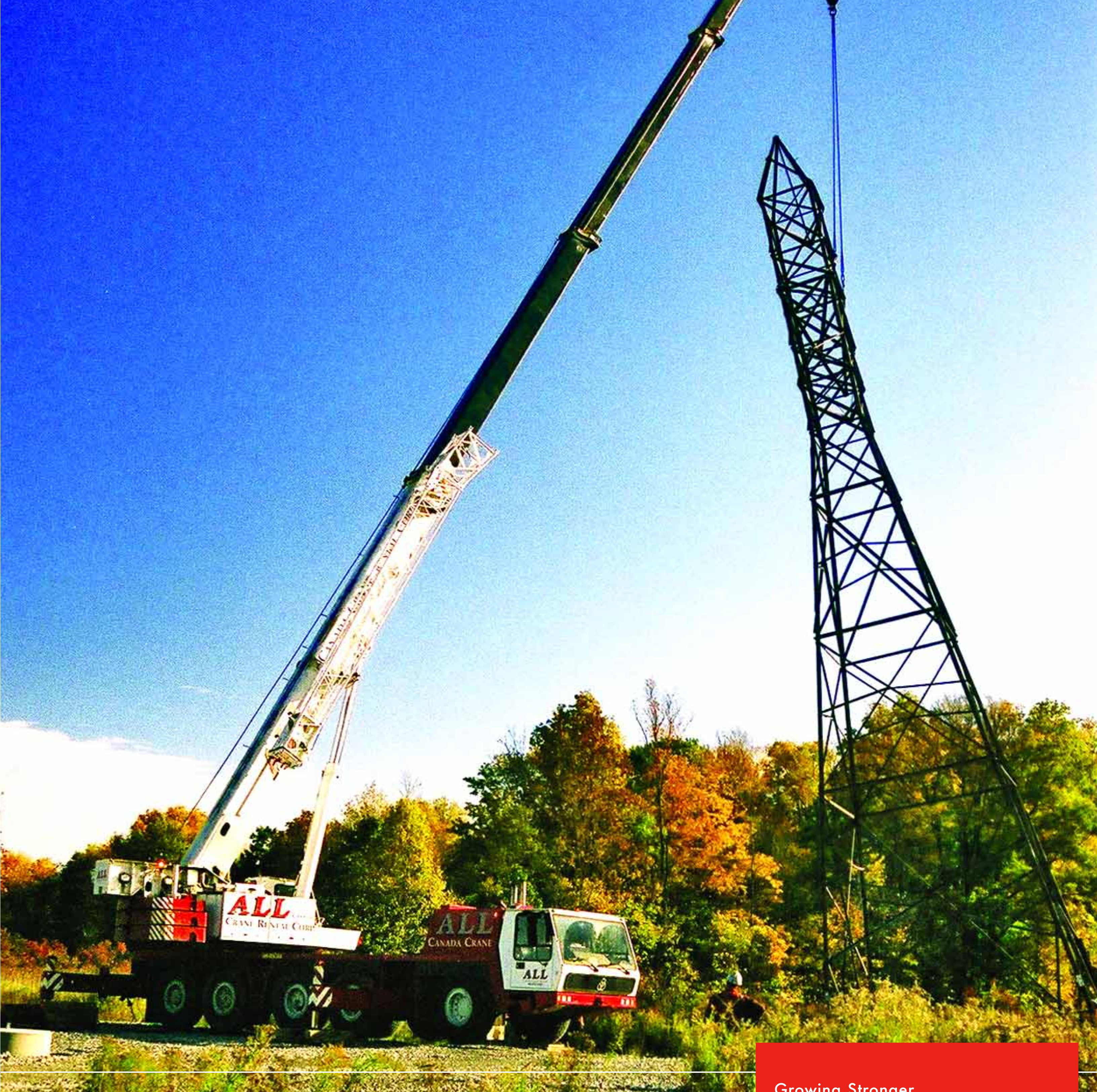
This project will also make new generation development possible in the Niagara Falls area, reduce the risk of supply shortages, allow for more efficient use of existing generation resources and reduce transmission line losses. It also improves Ontario's ability to import power from New York State when we need it. The start of construction in 2005 followed years of hard work on planning and approvals by employees across the Company. It has been included in our 10-year plan for several years. With the urgent need and the tight timeline, teams are working closely together to make sure the project stays on target. We are confident it will be delivered on time and on budget.

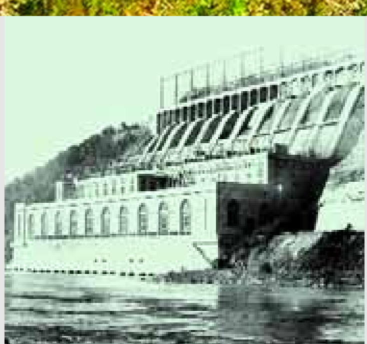
1930s
The Great Depression slows the demand for electricity.

1939
WAR! Ontario powers up to produce enough electricity to meet wartime production needs. Links with Quebec are established.

Left: Ontario Hydro linemen up the pole on June 11, 1947, were using hot line tools to work on "live" lines.

Left: Using single-horse power, these men made good progress in laying cable near Beamsville, Ontario, on November 22, 1923.





Left: The power of Ontario's waterways was the major source of electricity in the first half of the 20th Century.

Growing Stronger

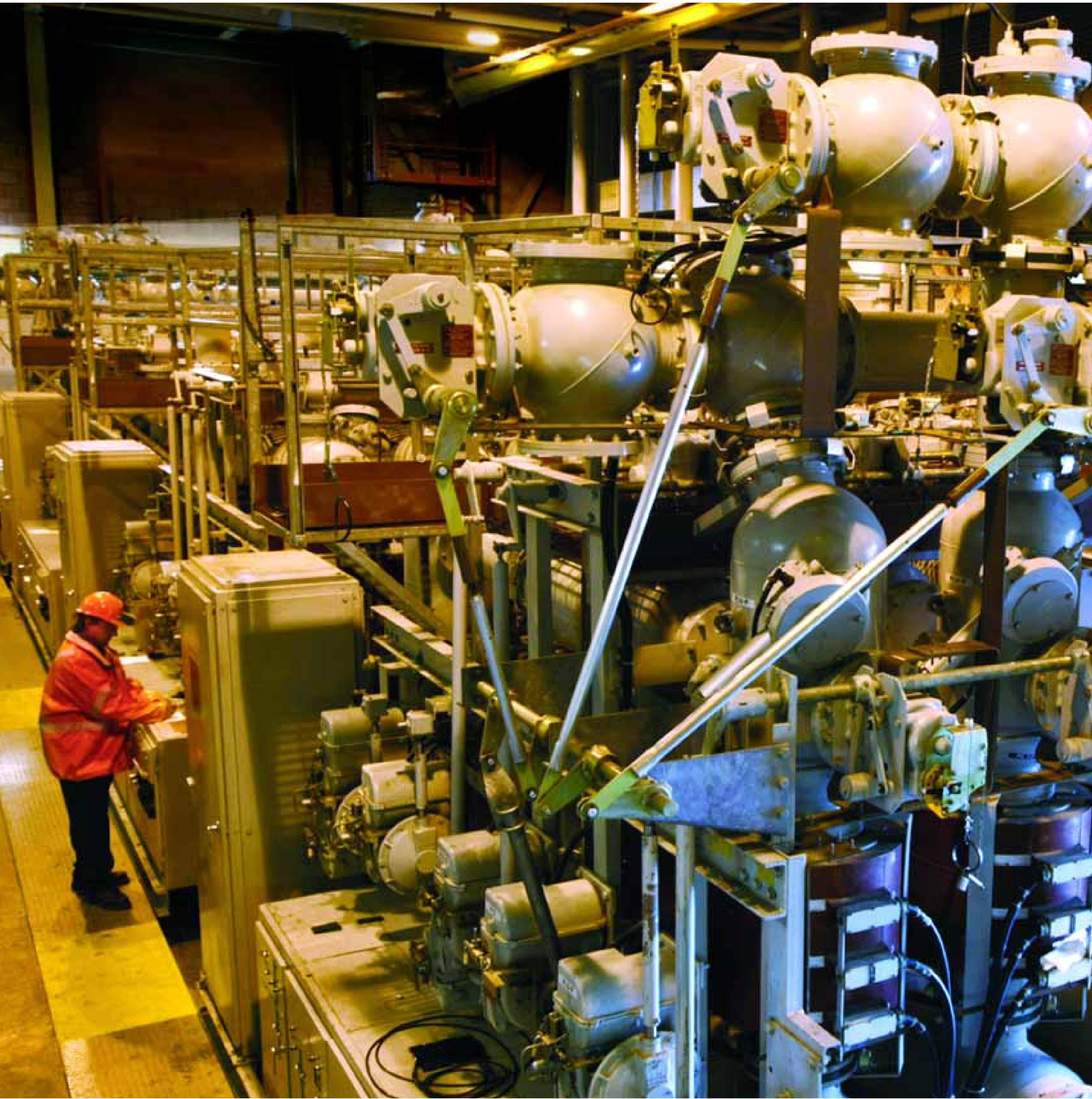
Above: Upgrading our system, like our Niagara Reinforcement project, is part of our core strategy for the years ahead. The Niagara project is expected to be completed by the summer of 2006 and will bolster our ability to deliver power from the Niagara region to southern Ontario.

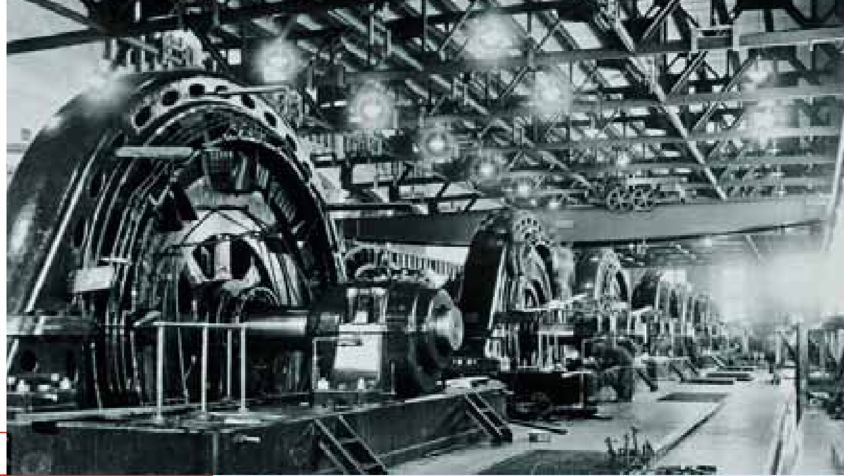
1941

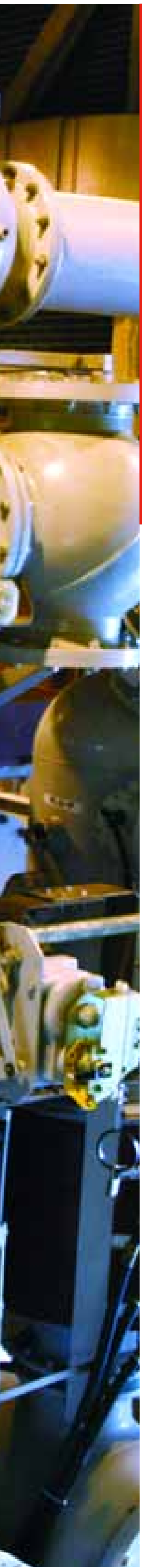
As part of the war effort, the first conservation program is started and customers are urged to "Save Hydro in Your Home: Help Win the War!"

1949 to mid 1950s

Power stations and transmission systems are centralized into one network for efficiency and flexibility. Ontario becomes compatible with the frequency of neighbouring provinces and states.







Vital Hub
Left: John Wright inspects equipment at the Cecil transformer station, a vital part of Hydro One's delivery system to downtown Toronto. Discreetly enclosed inside of a brick building, most people walking by wouldn't even notice the facility.

Feeding the System
Above: Water-powered generation plants like this one have been providing Ontarians with clean sources of electricity for more than a century.

Parkway transformer station

Parkway transformer station came into service in 2005, significantly strengthening the system supplying power to the GTA. It is part of our efforts to ensure power supply reliability to the GTA and to accommodate future growth. It strengthens the transmission system and supported the shutdown of the Lakeview generating station. The design, construction and start-up of this project on time and on budget is a tribute to the excellence of our employees.

Esplanade Cable Project

On March 11, 2005, the OEB approved our application to reinforce our electricity transmission facilities in downtown Toronto by constructing two new underground cable circuits between the John and Esplanade transformer stations. This project will reinforce existing infrastructure and allow us to deliver electricity to Toronto through a more flexible system. We began work in the fall, boring the tunnel beneath Toronto's subway system 30 metres underground connecting the two transformer stations, which are about 10 city blocks apart. We expect to have the cable in service in 2007.

forestry

Hydro One's lines traverse Ontario's roughest terrain. With 640,000 square kilometres of service territory we invest considerable time and effort to keep our lines clear of brush and trees. Downed trees and falling branches are a major cause of outages and keeping our lines clear improves reliability during stormy weather. In 2005, our forestry crews cleared 11,863 hectares of brush along our transmission corridors and 3,216 km of trees along transmission lines. We also cleared 9,076 km of our distribution lines.

In 2005 we moved further towards our target of returning our provincial clearing cycle on to a well-defined, seven-year clearing cycle for transmission lines and an eight-year clearing cycle for distribution lines. Carrying out our forestry program efficiently and consistently means fewer power outages caused by trees down on the lines.

Above: Forestry apprentices Jason Swant (front) and Frank Graves train in Cloyne, Ontario, to use Hydro One's advanced rigging system.

1950s
Hydro workers go door-to-door replacing more than 7 million appliance motors to match the new frequency.

1954–1958
The 1328-megawatt Sir Adam Beck 2 plant is built on the Niagara Gorge adjoining Sir Adam Beck 1.

1958
The 912-megawatt R.H. Saunders plant in Cornwall, Ontario is declared in service by Queen Elizabeth and American Vice-President Richard Nixon.

Left: This motor sled was used by a maintenance crew in the North Country in April 1942.

Left: Taken in 1943, this photo shows the transformer at the rear of the municipal office at Paris and a Hydro service truck.

Treetop Trimmers

Above: Hydro One foresters are highly trained to work on trees near live lines. Trimming and removing trees and brush helps prevent the inconvenience of power outages for our customers. Since 1999, we've reduced the number of outages by 10 per cent, largely through preventative measures like our forestry program.

Left: Before Ontario Hydro foresters could quickly rise to great heights in hydraulically operated buckets, they could rise to most occasions with the safety–tested equipment shown in this June 1947 photo.

1960
Construction of Canada's first 500,000–volt transmission line begins, connecting supply between northern Ontario and southern Ontario.

High Life
Left: Working on both our distribution and transmission system requires years of training and expertise.

working *safely*

In the last century, a quantum leap has been made in workplace safety. Early work on Ontario's electricity system exacted a significant human cost. From 1918 to 1928, the first decade of record keeping, 244 workers lost their lives building generating stations, stringing power lines and erecting towers. In the last decade, four workers died on the job working for Ontario Hydro's successor companies. Much of the credit for this dramatic improvement can be directly linked to the innovative ideas of the bright and dedicated employees of our company's predecessor. Today, the men and women of Hydro One proudly carry on that tradition. In recent years, we have introduced better work procedures, improved fall arrest equipment and techniques, arc-resistant clothing and advanced rigging techniques and improved design/equipment standards, to name a few.

While the evolution of safety is moving in the right direction, to Hydro One, zero is the only acceptable number. And we did not achieve it this year. On April 9, 2005, a Hydro One electrician was killed while working at our Cooksville transformer station. His loss is deeply felt and our sympathy goes out to his family.

While much has changed over the last 100 years, our primary hazards haven't. We work around and with electricity. We often work high above the ground. Annually, we log millions of kilometres driving on Ontario's highways and back roads, often in the worst weather conditions.

Front cover & page 20: Dan Butters

Left: This lineman was twisting absorber rods on cables when this picture was taken on January 18, 1932.

Airborne Line Maintainers

Left: Working on towers that are sometimes more than 200-feet tall either requires long hours of climbing or the expertise to step down from our AirStair device. The AirStair allows our helicopter to safely drop off and pick up line maintainers on top of our structures and was developed by Hydro One employees.

Know the Job

Right: From Left–Derrick Bridges, Mike Reid, John Bosomworth and Scott Punsit break down the job ahead. Before any work starts, each member of the team is briefed on the entire job and understands their role, the hazards and the role of everyone on the team.

On the Road

Left: Our crews spend countless hours driving and working alongside Ontario's roads. Driving and road safety training are a mandatory part of being on our team.

Our focus remains on achieving zero injuries caused by electrical incidents, falls and falling objects and those resulting from the operation of vehicles and equipment. Although we did not achieve our aspirational safety targets for 2005, we are closing the gap. The number of serious incidents was 12 per cent lower than 2004 and 28 per cent lower than 2003. Since 1999 our lost-time accident frequency rate has dropped by about half, putting us in the top quartile of Canadian transmission and distribution companies.

We continue to change our safety culture and infuse safety into every project and every decision, every day. From head office to the field, from Ottawa to Pigeon Lake, safety is our top priority and the entire company is committed to this goal.

In Towers We Trust

Above: Line maintainers see our beautiful province from a perch like this one on a tower in the London area. Maintaining the transmission system requires inspection with thermal reading equipment from trucks and helicopters and then repairing weak spots in the system.

Left: Stringing of transmission line on steel towers in the Niagara area is shown in this photo, dated February, 1910.

a workforce that *delivers*

By 2008, about a quarter of our workforce will be eligible for retirement. We are preparing for turnover in our workforce by actively identifying successors inside the company and drawing in new talent from outside. We are promoting careers in skilled trades and our recruitment efforts of university graduates are highly successful.

Hydro One is working with the Power Workers Union and our industry partners to recruit apprentices in lines and forestry so a skilled workforce is always there to take care of our system. We're also supporting co-op engineering programs at the University of Waterloo and other post-secondary institutions in Ontario.

Hydro One's labour relations strategy focuses on protecting shareholder value and providing for future economic stability for the Company. In 2005, we ratified collective agreements with four different unions. We were unable to reach an agreement with The Society of Energy Professionals, resulting in a 15-week strike that ended with an arbitrated settlement. In the arbitration award, the company achieved two-tier pensions, one of its key bargaining objectives. The less provident pension plan applies to future hires into Society-represented positions and translates into a 25 per cent cost-savings compared with the existing pension plan. This is in line with the reduced pension plan instituted for management employees hired after January 1, 2004.

We remain focused on increasing operational flexibility and decreasing labour costs so we can continue to deliver electricity to Ontarians at a fair price.

1970
One synchronized, province-wide grid is created, with the exception of remote communities.

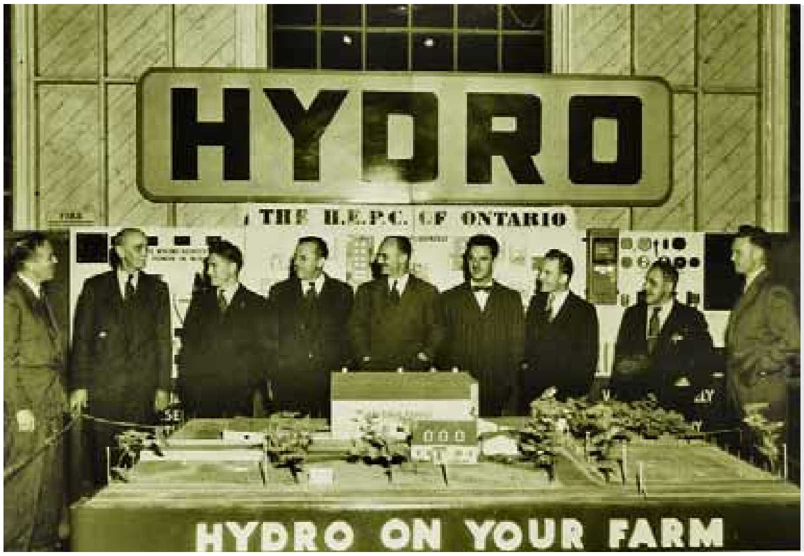
1971
Pickering nuclear generating station delivers nuclear powered electricity to Ontarians for the first time.

1977
The Bruce nuclear generating station comes into service.

Left: At the C.N.E. in 1936, Ontario Hydro "played up" the theme of "Better Light Better Sight."

Left: December 7, 1921. An early method of spooling out cable.

1989
The first unit of the Darlington nuclear generating station comes into service.



Left: Ontario Hydro's rural exhibit at the 1946 International Plowing Match at Port Albert.

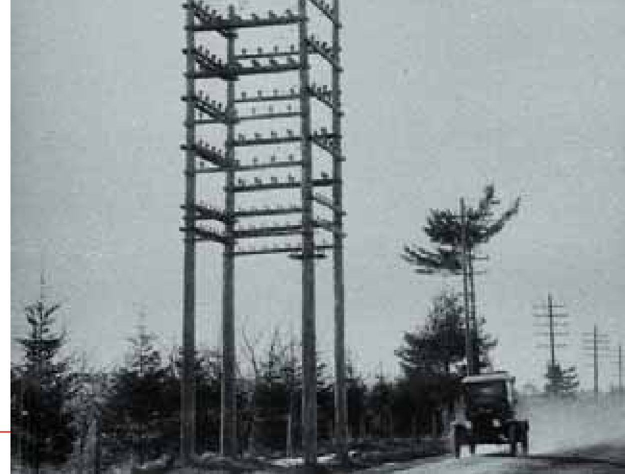
community and *conservation*

In the 1940s, Ontario Hydro asked Ontarians to conserve electricity to help with the war effort. In 2005, with demand almost outstripping supply and the system running at maximum capacity at peak hours, we're once again encouraging our customers to use electricity wisely.

With the cost of electricity rising, conservation has never been more important. Hydro One introduced several programs in 2005 to help Ontario communities cope with rising costs of electricity and reduce usage.

Low-income energy efficiency grant

Hydro One has teamed up with Canada Mortgage and Housing Corporation and Natural Resources Canada to provide financial incentives for energy-efficiency upgrades to low-income Hydro One customers who heat their homes with electricity. This is the first initiative of its kind in Canada, where three different organizations have come together to provide substantial benefits to homeowners who might not otherwise be able to afford upgrades. Under the Home Energy Efficiency Grant initiative, Hydro One is offering up to $3,000 per qualifying household.



Left: Community education at fairs and in schools is a vital part of Hydro One's corporate sponsorship program. We've dedicated $20,000 in each of three years towards energy and electricity workshops through Scientists in Schools and we've also committed to $150,000 over three years to expand the Advanced Coronary Treatment CPR programs in schools.

Below: Hydro One supports employees who volunteer with youth sports teams by providing sponsorship grants that make it easier for kids to get outside and play.

Above: Taken at Cooksville in March 1918, this photo shows what was known as a right angle structure.

knowledge is *using less power*

Hydro One's engineers had a question. If people know how much electricity is costing them on a real-time basis, does it affect the way they use this valuable commodity? To answer this question, our staff conducted a year-long real-time monitoring pilot-program. One of the largest studies of its kind undertaken in Canada, 500 of our residential customers volunteered to have their meters fitted with sensors that captured real-time electricity usage and transmitted it to a small screen in the house. The screen showed exactly how much electricity was being used that month and what it was going to cost the family. They could see the projected monthly amount go lower when they turned off the air conditioner. They could see it go up when they switched on every appliance in the house. By knowing the dollars and cents of their daily usage, our customers used less. Compared to the previous year, the pilot program families reduced their usage between 7 and 10%. Sometimes, knowledge means using less power.

Holiday LED exchange

Hydro One delivered holiday cheer in the form of energy savings to communities across Ontario by exchanging a new string of energy efficient Light Emitting Diode (LED) lights for two strings of old holiday lights. Using LEDs instead of traditional incandescent bulbs adds up to big energy savings over the holiday season. Compared to traditional lights, LEDs use up to 95% less energy, last at least 7 times longer, are more durable, with no filaments or glass bulbs to break and produce very little heat, reducing the risk of fire. Safe, smart and good value; now that's a great idea.

1997
We launch our first Web site, now called HydroOne.com.

1998
Heroic hydro workers toil in icy, freezing conditions to replace 10,750 poles, 1,800 transformers and 2,800 km of power lines destroyed by the Ice Storm.

1998
Ontario Hydro is broken up into five companies: Ontario Power Generation, Ontario Hydro Services Company, the IMO, OEFC and the ESA.

Left: Ontarians took great pride in the electricity delivery system in the 1950s and public tours of then "futuristic" control rooms were often in high demand.

Left: When the first nuclear plants were planned, Ontario Hydro spent a great deal of time on public information and education. When Hydro One embarks on a major project, community consultation is an important part of the plan.

Delivering Quality of Life

Left and above: Hydro One serves approximately 1.3 million distribution customers across Ontario. The electricity we deliver powers businesses, communities and families.

2000
Ontario Hydro Services Company is renamed Hydro One Inc.

2000 – 2002
Under a new legislative framework, Hydro One acquires 89 local distribution companies, increasing its customer base by 25 per cent to 1.2 million.

2002
Hydro One's Charity Trust program raises $650,000 for Ontario charities.

2003
A tree on a transmission line in Ohio causes a power outage that affects the entire Eastern Seaboard of North America. Hydro One crews worked rapidly to be able to deliver all available power within 24 hours.

Founding Father of Power in Ontario
Sir Adam Beck was a prosperous London, Ontario, manufacturer, who was simultaneously the Mayor of London and a member of the provincial legislature. Beck was an early champion of public power and lobbied hard to have the hydro-electric power resources at Niagara connected to communities across Ontario. In 1906, Beck became "Power Minister" and chairman of the Hydro-Electric Power Commission of Ontario, the world's first publicly-owned utility.

His initial project was to build a 110,000-volt transmission line from Niagara Falls to carry power to southwestern Ontario municipalities, including Toronto and 13 other communities. On October 11, 1910, Beck held his first ceremonial "switch-on" in Berlin (now Kitchener) to celebrate the completion of this line. When he pressed a switch and lit a street sign that read "For the People", the town went wild.

Before he died in 1925, Beck was instrumental in developing the 450-megawatt Queenston Chippawa power station at Niagara Falls. When it was commissioned, it was the largest power station in the world. In 1950, this station was renamed Sir Adam Beck I to honour his memory.

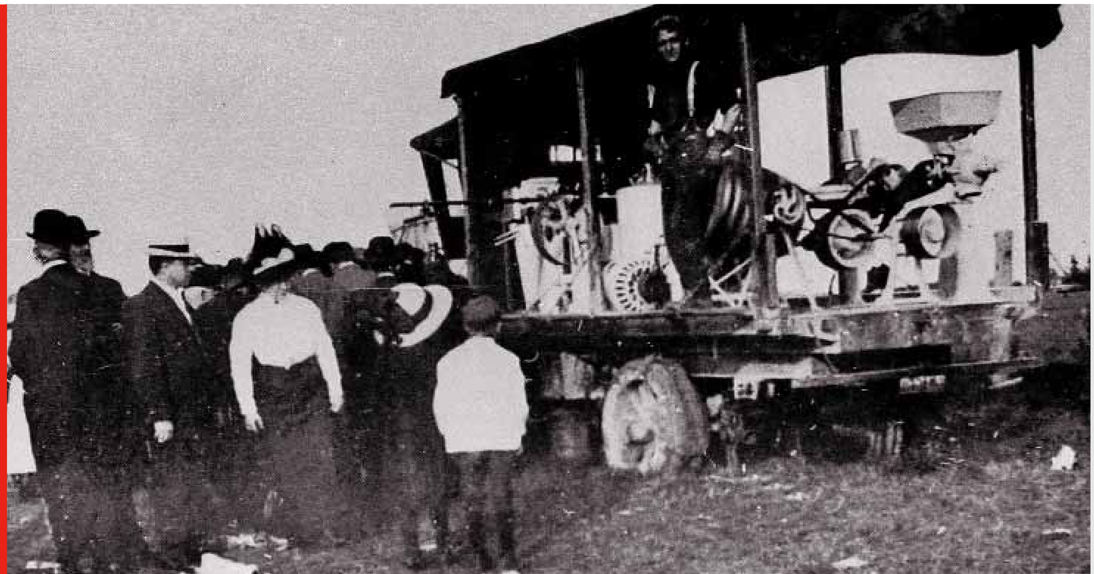
Above: Two units of the Adam Beck "Circus," which carried various appliances to the farms of Ontario to provide on-the-spot demonstrations, can be seen in the background of this photo taken in 1912. When they saw how easy it was to saw wood with Hydro, fewer and fewer farmers had axes to grind.

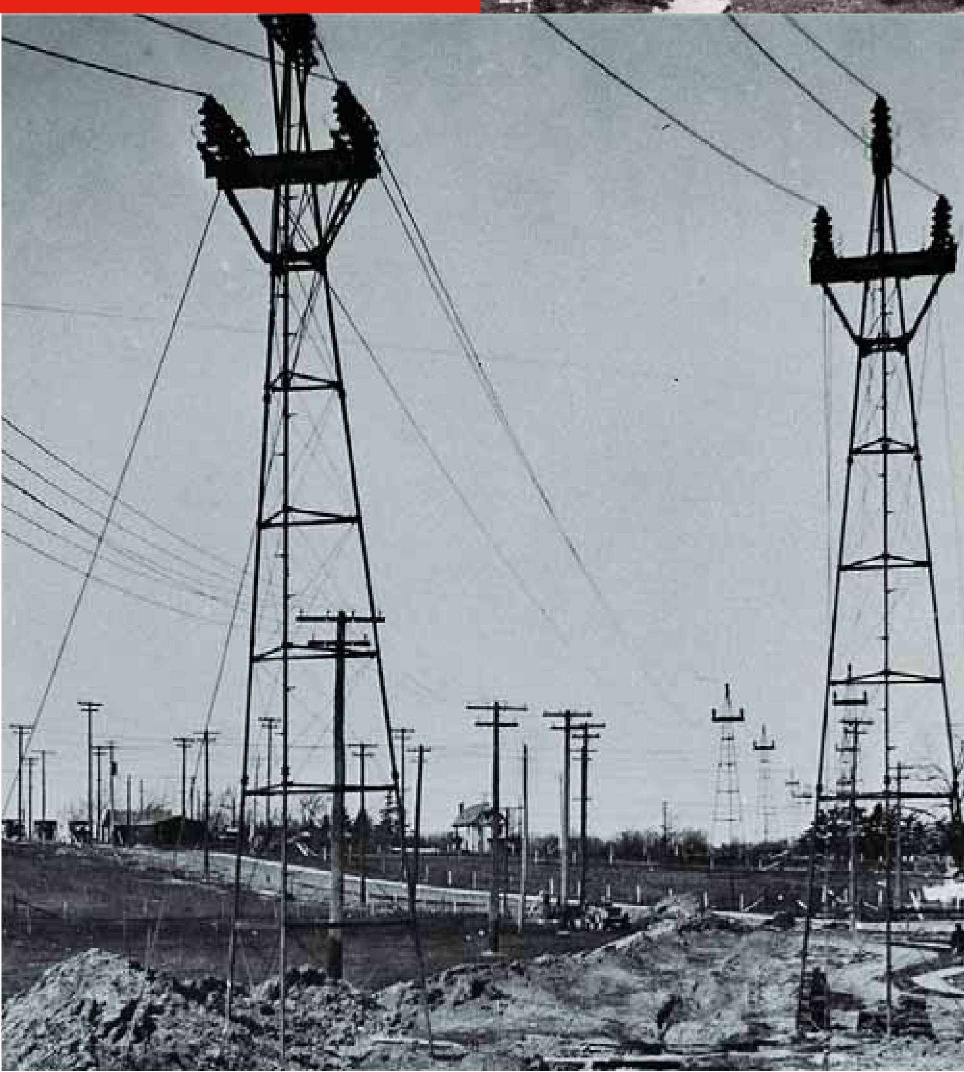
2004
Hydro One opens the Ontario Grid Control Centre, centralizing operation of the province's transmission and distribution centre in one facility.

2005
Work is completed on the Parkway transformer station to improve supply reliability and enable the shutdown of the coal-fired Lakeview generating station.

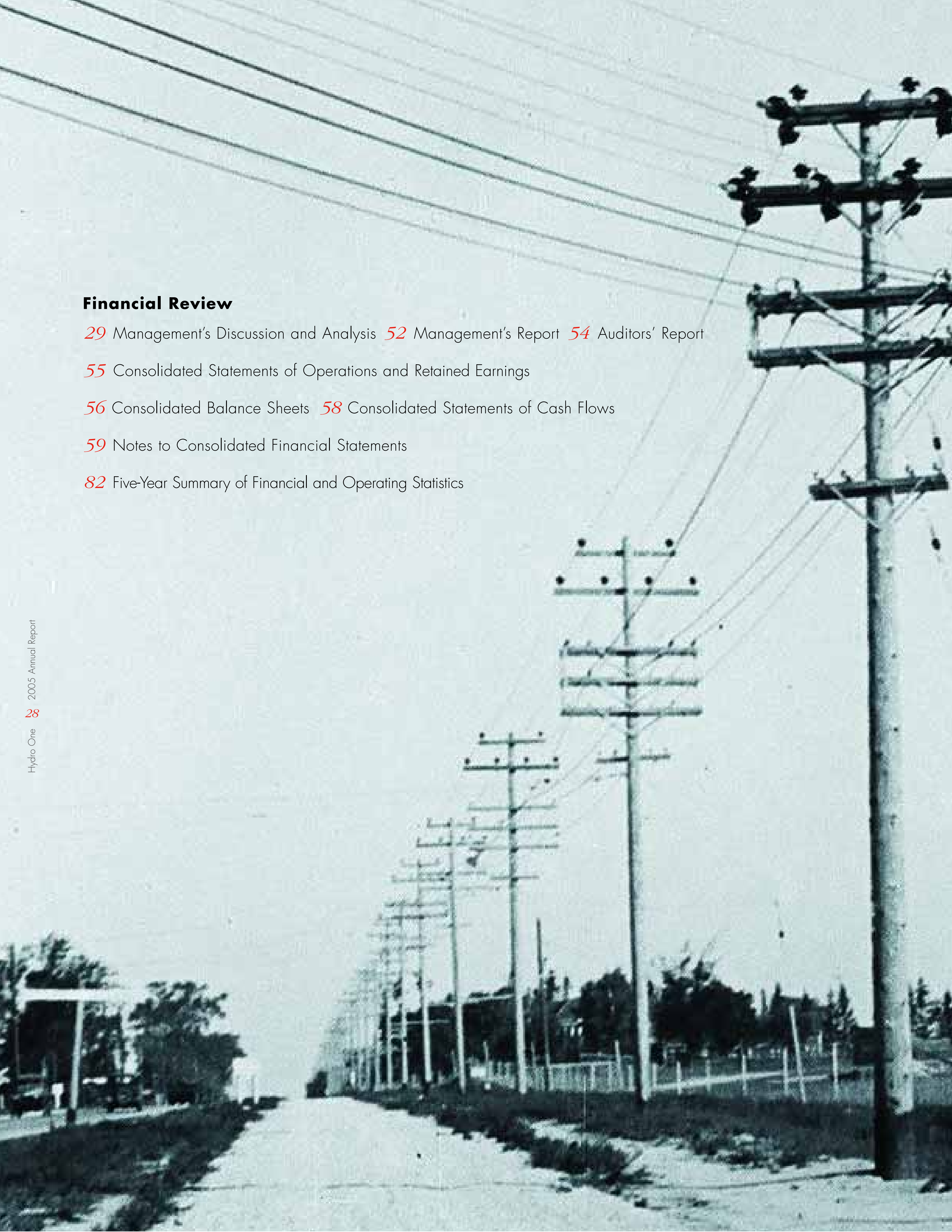
Present Day
As it was a century ago, it is today. The government of Ontario fully owns Hydro One, one of North America's largest transmission and distribution companies with almost 30,000 km of transmission lines, and approximately 1.3 million distribution customers.

Right: When the Adam Beck Circus was on the move, crowds would gather at its stops to see the latest electrically powered equipment.





Left: The earliest steel towers and high-voltage lines were quite a different shape than the one's we use today. This photo was taken in 1910, near Niagara Falls.



Financial Review

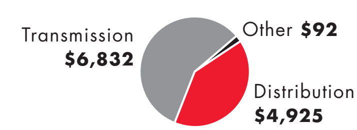
We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2005 and 2004.

OVERVIEW

We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario. Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2005, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

Transmission

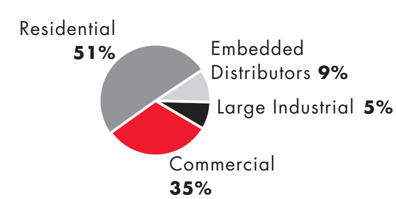
Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2005, we earned total transmission revenues of $1,310 million primarily by transmitting approximately 157 TWhs of electricity, directly or indirectly, to more than 4 million customers. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MWs and exports of approximately 5,800 MWs of electricity. In terms of assets, our transmission business is our largest segment, representing more than 50% of our total assets.



TOTAL ASSETS
December 31, 2005
(Cdn $ millions)

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, approximately half of our distribution revenues are earned from our residential customers.



2005 DISTRIBUTION REVENUES

Other

Our other business segment contributed revenues of $21 million in 2005 and has assets of about $92 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. We are currently in the process of assessing our strategy with respect to these operations.

OVERVIEW (continued)

Our Strategy

In 2005, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value. We seek to achieve these goals by continuing our focus on the following strategies:

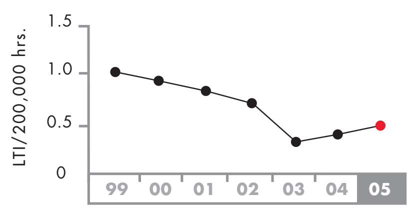
- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on prevention of serious injury.
- *Customer Service:* Become a leading customer-focused company. We will undertake initiatives and deliver on actions in a timely manner to improve our customers' level of satisfaction. In particular, we will strive to build positive relationships with all of our customer segments, acknowledging the commercial requirements of our large and mid-sized customers.
- *Reliability:* Enhance the reliability of our transmission and distribution systems while continuing to develop and expand the transmission system to meet Ontario's future needs.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining an effective borrowing capability through stable credit quality and delivering appropriate financial returns to our shareholder.

Performance Measures and Targets

We measure and target our performance in all the above strategic areas. We largely met our challenging 2005 objectives, improving in a number of areas over 2004 levels, and are moving forward to meet our strategic goals.

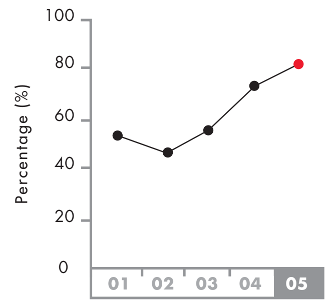
As we work in an environment with significant hazards, safety is our top priority. In 2005, we experienced an employee fatality at a transformer station. This unfortunate occurrence is a painful reminder of the workplace hazards that we deal with on a daily basis. Consequently, our focus remains on the goal of achieving zero injuries by 2006 for categories such as electrical incidents, falls and motor vehicle accidents where there is a high potential for serious injury. The number of serious lost time injuries has consistently remained at four per year over the last number of years. Although we did not achieve our aggressive safety targets for the year, the number of serious incidents in 2005 was 12% lower than 2004 and 28% lower than 2003.

As shown in the accompanying chart, since 1999 our lost-time incident frequency rate has dropped by about 50%, placing us in the top quartile of Canadian transmission and distribution companies. The majority of our 2005 lost-time incidents were related to minor injuries such as strains and slips. Going forward, we will continue to emphasize the importance of safety, with the goal of further improving our safety performance. This involves a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned safety initiatives include an injury and exertion prevention program, a coaching and mentoring program, developmental rotations, and a fleet safety program.



Lost-Time Incidents Frequency Rate

By addressing service issues, focusing on key areas of importance for our customers and upgrading our assets, we have made tangible improvements in customer satisfaction. We met all OEB targets for customer service. As shown in the accompanying chart, the level of satisfaction of our large transmission and local distribution company (LDC) customers improved by 14% over 2004 levels and 57% over 2003 results. Residential customer satisfaction levels remained consistently strong at 82%. Building on this momentum, we will continue to focus on improving the level of satisfaction of all our customers by undertaking initiatives which will streamline their points of contact and reduce our response time to customer requests.



Large Transmission & LDC Customer Satisfaction

We achieved all of our OEB targets for frequency and duration of interruptions. In particular, our transmission system reliability for frequency of interruptions out-performed our 2005 target and our 3-year average. The average duration of interruptions was within OEB targets, although slightly higher than the 3-year average (2002-2004), as a result of a late April freezing rainstorm in Southwestern Ontario and two outages on a remote line with limited accessibility. We continue to focus on the reliability of our distribution system. However reliability improvements are more challenging due to the rural nature of our system. Considering the impact of severe storms, we met our distribution reliability target for frequency and duration of interruptions and maintained the previous 3-year average (2002-2004). A number of key initiatives were undertaken during the year to enhance our performance, including improved crew scheduling to allow faster restoration response to unplanned outages. We also carried out detailed line reliability and customer impact analysis for use in developing investment requirements.

Strong financial performance again characterized our 2005 results and we maintained or improved our credit ratings on both our short and long-term debt.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates in proceedings through oral or written public hearings. These rates are based on the required level of revenue that the OEB allows for us to operate our regulated businesses, plus an approved rate of return.

Our industry has undergone significant restructuring over the past several years. On May 1, 2002, Ontario's wholesale and retail electricity markets were opened to competition (Open Access). Under Open Access, most consumers paid the wholesale spot market price for electricity as determined by demand and supply in the wholesale spot market administered by the Independent Electricity System Operator (IESO). In response to price volatility, the *Electricity Pricing, Conservation and Supply Act, 2002* was enacted to cap transmission and distribution rates and to fix the commodity price of electricity at 4.3 cents per kWh for low-volume and designated consumers.

As a result of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, the transmission and distribution rate caps were lifted. The fixed commodity price was replaced with a two-tiered pricing structure, effective April 1, 2004. Under this structure, low-volume and designated consumers paid 4.7 cents per kWh for the first 750 kWh of electricity consumed each month and 5.5 cents per kWh for electricity consumed over this threshold each month.

REGULATION (continued)

On December 9, 2004, the Ontario Legislature passed the *Electricity Restructuring Act, 2004* to provide consumers with stable prices that better reflect the true cost of electricity, facilitate new supply, and promote conservation and demand management. The act also created the Ontario Power Authority (OPA), which has a mandate to ensure an adequate, long-term supply of electricity in Ontario. The IESO continues to be responsible for overseeing and running the wholesale markets and ensuring the reliability of the integrated power system.

Under the new market structure, wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices for electricity. At the retail level, the OEB approved a Regulated Price Plan (RPP) for certain low-volume and designated consumers. The RPP maintained a two-tiered pricing structure, set new commodity prices, and introduced seasonal consumption thresholds for residential customers. The commodity price was based on an OEB forecast of the price of electricity over the period from April 1, 2005 to March 31, 2006 and was set at 5.0 cents per kWh for the lower tier and 5.8 cents per kWh for the upper tier. The consumption thresholds for residential customers were 750 kWh for the 2005 summer months (April 1 to October 31) and 1,000 kWh for the winter months (November 1 to April 30). For the 2006 summer months (May 1 to October 31), the threshold for residential customers will be 600 kWh. For all other RPP customers, the consumption threshold is 750 kWh year-round. The OEB intends to review these prices semi-annually starting May 1, 2006. The price plan also introduced time-of-use pricing for those customers with smart meters. Unexpected shortfalls or overpayments will be administered by the OPA and passed through to customers over the course of a year, starting on a price resetting date. As a result, our distribution business does not have commodity price risk.

On November 3, 2005, the Government of Ontario (Government) introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by 2007, with installation in all homes and businesses to be completed by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. LDCs, including our distribution businesses owned and operated by our wholly-owned subsidiaries Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton), will own, install, operate and maintain the meters.

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. Existing rates were set based on cost of service rate regulation. The OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity, which in the last rate-setting period was targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB will consider options to track net income excesses or deficiencies from OEB-approved returns for the period from January 1, 2006 until the revised transmission rates are implemented. The options identified by the OEB include the possible use of a regulatory deferral account or an earnings-sharing mechanism.

On November 23, 2005, we submitted a proposal to the OEB that any excess earnings be returned to customers in the form of transmission system expansion projects that are critical to the economic health of Ontario and to the secure operation of the system. The approval of any earnings sharing mechanism could have a significant impact on our net income. We participated in an oral hearing on this matter and we anticipate a decision from the OEB in the first quarter of 2006. We also anticipate submitting evidence this summer in preparation for a transmission rate hearing expected to be held this fall. A 1% change in the return on deemed common equity of the transmission business, would affect our net income by about $22 million.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue will decrease by approximately $13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates are approved by the OEB, based on a revenue requirement that includes a rate of return. Our distribution rates continue to be set based on cost of service rate regulation. Our current rates include a targeted return of 9.88% on deemed common equity. In August 2005, we filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. If approved, customers would see an average increase of 6% on their monthly bills starting in May 2006. This rate application is currently in the evidentiary phase. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006.

In December 2004, we received OEB approval to recover certain distribution-related deferral account balances, over the period ending April 30, 2008. The recovery of these prudently incurred costs was originally suspended by the *Electricity Pricing, Conservation and Supply Act, 2002*. These deferred amounts primarily include charges for low-voltage services to embedded LDCs and direct customers, market-ready transition costs, retail settlement variance account balances, and certain environmental costs. In March 2005, the OEB also approved our application to implement the final installment of a rate increase associated with moving toward our allowable return on equity that was originally to be effective for all LDCs on March 1, 2003. Our distribution rates were increased on April 1, 2005 to reflect these decisions.

We also filed a distribution rate application seeking approval for a $3 million increase in the 2006 distribution revenue requirement of Hydro One Brampton, which would result in customers seeing an average increase of 1% on their monthly bills starting in May 2006. This rate application is subject to a separate OEB process, independent of the Hydro One Networks' distribution application.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	2005	2004	$ Change	% Change
Transmission	**1,310**	1,262	48	4
Distribution	**3,085**	2,874	211	7
Other	**21**	17	4	24
	4,416	4,153	263	6
Average annual Ontario 60-minute peak demand *(MW)*[1]	**23,074**	22,375	699	3
Distribution – units distributed to customers *(TWh)*[1]	**29.7**	28.5	1.2	4

[1] System related statistics include preliminary figures for December.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover the necessary revenues to support a transmission system that has sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

The increase in transmission revenues in 2005 primarily reflects the extreme weather conditions experienced during the summer of 2005, which was one of the hottest on record. Temperatures in excess of 30°C were common, resulting in the previous record for electricity consumption of 25,414 MW being exceeded on seven occasions. In July, the new record peak demand was set at 26,160 MW. Only the summers of 2002 and 1998 have been comparable since 1970. Peak demand increases, compared to 2004, were also experienced in some of the remaining months of the year. Ancillary transmission revenues were marginally lower this year.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include minor amounts of ancillary distribution services revenues, such as fees for the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased in 2005 compared to last year mainly due to the recovery of higher purchased power costs of $144 million, as described below under "Purchased Power." The remaining increase primarily reflects an OEB-approved distribution tariff rate increase effective April 1, 2005, the recognition of low-voltage services revenues, and increased demand. The approved tariff increase was originally scheduled to be effective March 1, 2003, but was subsequently suspended for all LDCs by the *Electricity Pricing, Conservation and Supply Act, 2002*. During 2004, the low-voltage services revenues were deferred until a December 2004 prudence decision by the OEB allowed for regulatory recovery starting in 2005. Ancillary distribution revenues were lower this year primarily due to a lower level of assistance required by Florida Power and Light Company to repair hurricane damage in 2005. In 2004, our crews were called upon twice to provide hurricane recovery assistance, compared to once in 2005. Such assistance is carried out under a North American mutual-assistance agreement.

Under a new regulation issued in October 2005, RPP customers received the *Ontario Price Credit,* reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter, revenue and cost of power were both reduced by approximately $140 million, representing the amount refunded to customers. The application of the *Ontario Price Credit* did not result in any adjustment to net income in the current period or in previously reported periods.

Other

Other revenues were higher by $4 million compared to 2004 due to increased lit fibre revenues within our telecommunications business.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. Prior to April 1, 2004, for certain low-volume and designated customers, the commodity price of electricity was fixed at 4.3 cents per kWh. On April 1, 2004, this fixed rate was replaced by an interim two-tiered pricing structure of 4.7 cents per kWh for the first 750 kWh consumed each month and 5.5 cents per kWh for electricity consumed over this threshold each month. On April 1, 2005, the interim pricing structure was replaced by the OEB's RPP which consists of a two-tiered pricing structure of 5.0 cents per kWh for the first 750 kWh consumed each month and 5.8 cents per kWh for any additional consumption. Effective November 1, 2005, the first 750 kWh threshold was increased to 1,000 kWh during the winter months for residential customers. Customers who are not eligible for the RPP continue to pay market prices for electricity, adjusted for the difference between market price and regulated and contract prices paid to generators under the *Electricity Restructuring Act, 2004*.

Purchased power costs increased by $144 million, or 7%, to $2,131 million in 2005 compared to last year. This increase primarily reflects higher demand of $84 million and higher commodity prices of approximately $60 million. Commodity prices reflect higher wholesale prices for customers who are not eligible for the RPP, partially offset by lower net prices for RPP customers. The increased commodity prices due to the implementation of the April 2004 and April 2005 pricing structures for RPP customers, were more than offset by the mandated *Ontario Price Credit* associated with lower commodity prices between April 1, 2004 and March 31, 2005 as described above under "Distribution Revenues."

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004	$ Change	% Change
Transmission	**353**	356	(3)	(1)
Distribution	**413**	392	21	5
Other	**26**	23	3	13
	792	771	21	3

RESULTS OF OPERATIONS (continued)

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way were marginally lower than in 2004. Overall we maintained our necessary work program levels consistent with our safety and reliability standards at our transmission sites. We did experience lower station maintenance costs across our system as conditions, primarily caused by the abnormally high temperatures during the summer months, constrained our ability to take our equipment out of service for maintenance. As a result, additional maintenance is expected to be required in future periods. The reduction in these work program expenditures was substantially offset by higher expenditures from increased brush and line clearing activities, higher preventive maintenance on certain of our facilities and higher costs related to the reassignment of resources to support maintenance activities due to the smaller transmission capital program this year. Other cost reductions resulted from a labour disruption and from cost recoveries associated with insurance settlements and bad debts.

Distribution

Operation, maintenance and administration expenditures required by our distribution business to serve communities across Ontario were $21 million higher than last year. We maintained an enhanced forestry work program on our province-wide rights-of-way to improve reliability by reducing our trimming cycles. We also incurred increased expenditures to restore power due to intense storm activity this year. As required by the OEB, we also initiated our conservation and demand management programs in support of developing a conservation culture. These overall cost increases were partially offset by lower costs resulting from a labour disruption and lower costs required to provide emergency hurricane relief to Florida Power and Light Company.

Other

Other operation, maintenance and administration costs were $3 million higher this year compared to 2004. This result reflects the higher level of lit fibre service revenues.

Depreciation and Amortization

Depreciation and amortization expense for 2005 increased by $7 million, or 1%, to $487 million relative to the comparative period. This change primarily results from increased fixed asset removal costs, including such costs attributable to our Niagara Reinforcement Project which started in the last quarter of 2005.

Financing Charges

Financing charges decreased by $6 million, or 2%, to $325 million compared to last year. The reduction was due to the effect of higher interest capitalization on our regulatory assets associated with the OEB's December 9, 2004 rate decision, partially offset by the impact of higher average debt levels.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by $21 million, or 12%, to $198 million compared to 2004. A higher tax provision on higher income this year was partially offset by the recognition of a tax benefit of approximately $21 million relating to accumulated tax losses of a subsidiary. The tax benefit was recognized during the second quarter of 2005 after an agreement was reached to settle an outstanding legal claim that allowed for the dissolution of the subsidiary.

Net Income

Net income in 2005 increased $76 million, or 19%, to $483 million compared to 2004, excluding the impact of last year's one-time regulatory recovery. This increase primarily reflects higher tariff revenues within our transmission and distribution businesses. We maintained an intense focus on the operation of our equipment during the abnormally hot summer to ensure continuous, reliable delivery of electricity to Ontarians. In addition, we experienced a favourable impact on our results due to the recognition of a tax benefit related to the accumulated tax losses of one of our subsidiaries. These impacts were partially offset by higher operations, maintenance and administration expenditures, primarily within our province-wide distribution business. Including last year's one-time regulatory recovery, which was caused by the suspension of an approved rate increase under the *Electricity Pricing, Conservation and Supply Act, 2002*, our net income decreased by $15 million, or 3%, compared to 2004.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2004 through December 31, 2005. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2005				2004			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues[1, 2, 3]	**1,025**	**1,179**	**1,018**	**1,194**	1,074	1,018	960	1,101
Net income[1, 2, 3, 4]	**104**	**133**	**115**	**131**	186	133	59	120
Net income to common shareholder[1, 2, 3, 4]	**99**	**129**	**110**	**127**	181	129	55	115

[1] Both the revenue and the net income amounts reported in the first and second quarter of 2004 have been reduced by $5 million and $6 million, respectively, to reflect a change in interperiod allocations.

[2] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[3] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income in the current period or previously reported periods.

[4] As a result of submitted oral and written evidence, on December 9, 2004 the OEB issued a ruling citing prudence and approving recovery of amounts, previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought in our May 31, 2004 submission. Consequently, net income for the fourth quarter of 2004 includes a regulatory recovery of $91 million.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	2005	2004
Operating activities	**1,170**	911
Investing activities		
Capital expenditures	**(691)**	(727)
Financing activities		
Long-term debt issued	**500**	540
Long-term debt retired	**(648)**	(472)
Short-term notes payable	**(40)**	15
Dividends paid	**(291)**	(265)
Other financing and investing activities	**–**	26
Net change in cash and cash equivalents	**–**	28

Operating Activities

Net cash generated from operations increased by $259 million compared to 2004. This increase is primarily attributable to lower working capital requirements and a higher level of net income this year, excluding last year's one-time non-cash regulatory recovery. Our working capital requirements have primarily been affected by funding received from the IESO to process the mandated credit for RPP customers. This funding had a positive impact on working capital due to the timing of customer billing cycles. In addition, changes in our trade accounts payable balances reflecting our work program and the timing of tax payments contributed to the reduction in our working capital requirements.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks which matures in August 2006 and has a two-year extension option. As at December 31, 2005, we had no short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2006 and 2043. We currently plan to refinance maturing debt principally through our medium-term note program, which was renewed in June 2005. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which the full amount is remaining and is currently available until July 2007.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (low)	A
Moody's Investors Service Inc.	Prime-1	Aa3

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement that supports our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. As at December 31, 2005, we were in compliance with all of these covenants and limitations.

During 2005, we issued $500 million in long-term debt prior to the renewal of our medium-term note program and we repaid $648 million in maturing long-term debt. In comparison, during 2004 we issued $540 million in debt under our medium-term note program and we repaid $472 million in maturing long-term debt. In 2005, we decreased our short-term notes by $40 million compared to an increase of $15 million in 2004.

In 2005, we paid dividends to the Province in the amount of $291 million, consisting of $273 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $247 million and preferred dividends of $18 million.

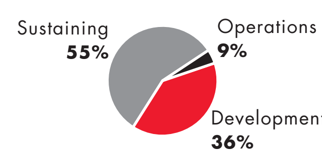
Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004	$ Change	% Change
Transmission	**349**	432	(83)	(19)
Distribution	**338**	288	50	17
Other	**4**	7	(3)	(43)
	691	727	(36)	(5)

Transmission

Transmission capital expenditures were $349 million and $432 million in 2005 and 2004, respectively. Capital expenditures to expand and reinforce our transmission system decreased by $98 million to $125 million, primarily due to the completion of the Parkway transformer station this year. This project was initiated last year in response to growing loads and the closure of the Lakeview generating station. In 2004, we also completed our Ontario Grid Control Centre, enabling us to access cost efficiencies and allowing for improved customer response and advanced monitoring and analysis of our system. Late in the current year, we began construction of our Niagara Reinforcement Project. This critical infrastructure project includes a new transmission line which will alleviate transmission constraints in the Niagara region and allow additional clean energy from Niagara Falls and electricity imports to reach consumers. Cost recovery will be subject to the provision of evidence regarding the economic benefits of this project. Capital expenditures incurred to sustain our transmission lines and stations, and to maintain reliability, increased by $17 million to $193 million, reflecting refurbishment and minor component replacement projects which did not require our equipment to be taken out of service. However, due to constraints, such as the effect of an abnormally hot summer, we did not fully complete our planned sustainment program this year and we anticipate completing such projects in future periods. Our other capital expenditures decreased marginally by $2 million to $31 million.

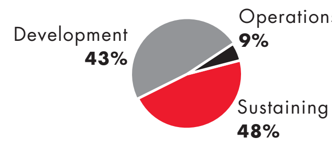


2005 Transmission Capital Expenditures

LIQUIDITY AND CAPITAL RESOURCES (continued)

Distribution

Distribution capital expenditures were $338 million in 2005 compared to $288 million in 2004. Capital expenditures to sustain our distribution system increased by $46 million to $162 million, primarily due to increased investments related to storm damage recovery and transport and work equipment, including new brushing equipment expected to further enhance productivity within our forestry program. In addition, other capital expenditures to support our distribution network increased by $14 million to $29 million, primarily as a result of increased investments in information technology assets. Capital expenditures to expand and reinforce the low-voltage distribution system declined by $10 million to $147 million. This reduction reflects the reprioritization of work during the labour disruption, partially offset by increased demand for new connections.



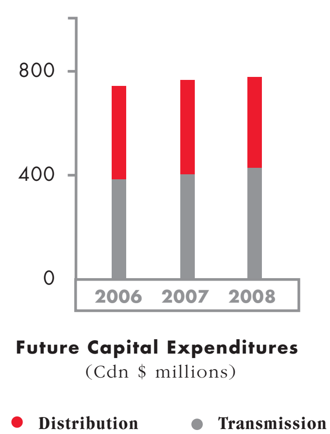
2005 Distribution Capital Expenditures

Other

Other capital expenditures decreased by $3 million to $4 million. The level of expenditures reflects the timing of projects to meet customer demand for new services.

Future Capital Expenditures

Our capital expenditures in 2006 are budgeted at about $755 million, an increase of approximately $65 million over 2005 actual levels but consistent with 2005 budgeted levels. Capital expenditures for 2005 were lower than budget due to constrained outage availability resulting from the hot summer, as well as the impact of a labour disruption and our efforts to focus on delivering the capital projects with the highest priority. The 2006 capital budgets for our transmission and distribution businesses are about $390 million and $360 million, respectively. Other capital expenditures are budgeted at $5 million and are largely minor enhancements to our fibre-optic network in support of our telecommunications business. Capital expenditures, as shown in the accompanying chart, are expected to increase marginally over the next few years, primarily reflecting investments in transmission infrastructure. There is also the potential for large-scale transmission infrastructure projects and conservation initiatives not included within our current investment plan due to the level of uncertainty, complexity and cost. These potential investments, together with our planned capital expenditures program, are discussed below.



Future Capital Expenditures
(Cdn $ millions)

Transmission

Transmission system capital expenditures are expected to increase marginally over the period 2006 to 2008. Given continuing supply constraints, we will focus on critical transmission assets that support generation facilities, such as our 500kV lines and high-voltage switch yards. The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Key transmission investment areas are power equipment, protection and control equipment, ancillary systems and overhead and underground lines.

In addition, increased expenditure levels reflect transmission development work identified in our 10-year transmission plan, *Transmission Solutions 2005-2014*. These investments ensure that growing area supply needs, reliability requirements, and needs for increased access to the Ontario market are successfully met. A number of specific development initiatives are nearing completion or are well underway, including the Niagara Reinforcement Project and the construction of underground transmission cables to improve reliability in downtown Toronto.

At the local level, we continue to proactively address supply needs with our customers. For projects required to provide reliable supply to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes continues to be essential for maintaining the safe and reliable delivery of electricity. Examples of projects initiated to meet the growing needs of our customers include: Holland transformer station to serve northern York Region; Belle River transformer station to serve areas in Essex County; and Everett transformer station to serve southern Simcoe County. In addition, we are in discussions with a number of customers in the areas of Kingston, Durham Region, Burlington, and in a number of communities in Western and Northwestern Ontario.

The timing of many of these projects and others is uncertain as they are dependent upon need and, in some instances, require approvals by various regulatory bodies, as well as negotiations with customers, neighbouring utilities and other stakeholders. In addition, the OPA is expected to file an Integrated Power System Plan (IPSP) with the OEB during the summer of 2006. The IPSP will detail how Ontario's medium and long-term electricity needs will be met, consistent with the public interest. Using our 10-year transmission plan as a basis, we continue to work closely with the OPA on transmission solutions to address these needs.

The IPSP could include additional large-scale projects which are not currently included in our investment plan. These major initiatives may be necessary to increase the supply of electricity and to support the closure of coal-fired generation. We are actively participating in various working groups involving key government and electricity industry stakeholders in this respect. In particular, we continue to develop interconnection enhancement possibilities with our neighbouring utilities, including those required to support the Government's existing and future power purchase agreements with the Province of Manitoba which could increase transmission capacity by up to 1500 MW. Planning also continues on a number of other major initiatives, including the development of a major new supply line between Central and Western Ontario to accommodate new power developments and enable the shutdown of the Nanticoke coal-fired generation station. As well, planning continues on the development of a major new supply line to Toronto to enhance reliability. We would not undertake these large complex projects without a reasonable expectation that such expenditures would be recoverable in our rates.

Distribution

We continue to replace and improve our aging distribution asset base in order to improve system reliability. Increasing investments will be made within the distribution business, in particular reflecting increased wood pole replacements, feeder sectionalization and defect management. Across Ontario, we are continuing the replacement of older distribution systems with higher voltage and more current-standard installations. In addition, we are constructing new lines and stations in response to system growth forecasts or high load relief requirements, and will focus our efforts on making the distribution system more efficient. Examples of some of these initiatives include a new station to serve northern King Township and various projects to reduce losses on our distribution system.

LIQUIDITY AND CAPITAL RESOURCES (continued)

In addition, we are moving forward with initiatives to improve the reliability performance of our distribution system. Cost-effective improvements can be achieved by enhancing maintenance practices and the operability of the system by continuing to add sectionalizing capability at selected locations to reduce the number of customers affected by system outages. We will continue to implement a range of conservation and demand management programs consistent with our OEB-approved program.

In November, 2005, the Government introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be complete by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. LDCs will own, install, operate and maintain the meters and continue to bill their customers. This program is expected to increase our expenditure levels and reduce our tariff revenues. It is estimated that our costs could range from $600 million to $1.2 billion, depending on the technology platform selected and the associated infrastructure requirements. This estimate includes not only the acquisition and installation costs of smart meters, but also the costs of necessary billing system upgrades, telecommunication infrastructure and data management systems. Although there continues to be a high level of uncertainty surrounding the implementation details of the smart meters program, we anticipate that the resulting expenditures will be recoverable. The OEB is examining how to address any negative impacts associated with load reductions.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2005 (Canadian dollars in millions)	Total	2006	2007/2008	2009/2010	After 2010
Contractual Obligations *(due by year):*					
Long-term debt	5,084	589	895	800	2,800
Inergi LP (Inergi) outsourcing agreement[1]	600	110	205	183	102
Operating lease commitments	17	5	8	4	—
Total Contractual Obligations	**5,701**	**704**	**1,108**	**987**	**2,902**
Other Commercial Commitments *(by year of expiry):*					
Bank line[2]	750	750	—	—	—
Letters of credit[3]	106	106	—	—	—
Guarantees[3]	275	275	—	—	—
Pension[4]	89	81	8	—	—
Total Other Commercial Commitments	**1,220**	**1,212**	**8**	**—**	**—**

[1] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[2] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2006, with a two-year extension option.

[3] We currently have bank letters of credit of $82 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $21 million and parental guarantees of $275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one-month in arrears. Contributions after 2006 will be based on an actuarial valuation effective no later than December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, the company currently estimates annual pension contributions for 2007 and beyond to be in the range of $100 million.

The long-term debt amounts in the above table are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or within our capital expenditures, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our statement of operations or within our capital expenditures.

RISK MANAGEMENT

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. The Hydro One Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices and our Chief Financial Officer for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Regulatory Risk

On August 17, 2005, we filed a rate application seeking approval for a $160 million increase in the 2006 revenue requirement of Hydro One Networks' distribution business. As this is our first full cost of service rate submission since 1999 and as recent rate increases and commodity price increases have increased customer bills, we expect this submission to be closely examined by the OEB and intervenors. This could result in increased regulatory risk. For example, past or future expenditures could be disallowed or elements of the approved revenue requirement could be delayed. In addition, within the scope of this review, the OEB will examine the recoverability of certain pension costs incurred within our distribution business and recorded in a regulatory asset account. In accordance with an order from the OEB, we deferred the non-capital portion of our distribution-related pension costs incurred in 2004 and 2005 as a regulatory asset. These deferred expenditures amounted to $76 million as at December 31, 2005, inclusive of interest. Should the OEB determine that some of these expenditures are not recoverable from customers, any disallowed amount will be charged to the results of operations when the decision is rendered.

RISK MANAGEMENT (continued)

The OEB's December 9, 2004 decision, which allowed for regulatory recovery of the majority of the regulatory asset amounts we applied for, has significantly reduced the proportion of our total regulatory asset balance at risk for future disallowance. However, there may still be some residual risk of future OEB disallowance of unreviewed account balances. In the event that some of these amounts are disallowed by the OEB during our 2006 rate review, any disallowed amount will be charged to the results of operations when the decision is rendered.

On October 26, 2005, the OEB initiated a proceeding to approve revenue requirements for our transmission business for the years 2006, 2007 and 2008. For the period from January 1, 2006 until revised rates are implemented, the OEB intends to track net income in excess of the currently approved returns. Tracking options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism. This results in a risk of having some of our transmission revenues (for the period from January 1, 2006 until new rates are implemented) recaptured if excess earnings occur. We have proposed an earnings-sharing mechanism that would result in any over earnings being returned to customers in the form of transmission system expansion projects that are critical to the economy of Ontario and to the secure operation of the system. Our proposal is consistent with practices recently utilized in other North American jurisdictions requiring significant system investments. A hearing on our proposal was held on November 25, 2005 and a decision is expected by the OEB in the first quarter of 2006. The initiation of a transmission proceeding also results in similar risks to those faced by our distribution business as a result of our recent rate application.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful conservation and demand management programs. The OEB has recognized the need to compensate utilities for any resulting lost revenue, but the approach, level and timing of any such compensation mechanism are yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets and compensating us by paying the net book value of bypassed assets as well as costs of removal and environmental remediation. This code revision could result in compensation that is not consistent with the value of retaining the assets. The *Transmission System Code* enables us to challenge investments by utility customers that may strand our assets. We intend to use this avenue to mitigate any substantive financial risks.

There is also a risk that we could be required to invest in large-scale transmission infrastructure projects and conservation initiatives, such as smart meters. While we expect these expenditures to be fully recoverable, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment in value and charges to our results of operations. We have no insurance for naturally occurring damage or catastrophe impacting our assets located outside of our transmission and distribution stations.

Ownership by the Province

The Province owns all of our outstanding shares and therefore controls our company. The Province has the power to determine the composition of our Board of Directors and may directly influence our major corporate decisions and business plans. As such, in making decisions that affect us, the Province can be expected to consider the best interests of all of the residents of Ontario as well as the specific interests of our company and our customers. Examples of areas where this balance must be exercised include structuring and regulating our company and Ontario's electricity industry, regulating environmental issues and determining the amounts to be paid by us as dividends.

Labour Risk

Approximately 25% of our staff are eligible for retirement by 2008. We expect the skilled labour market for our industry to be highly competitive in the future. If we are not able to attract or retain sufficient qualified staff, our operations and financial condition could be adversely affected.

We have a defined benefit registered pension plan for the majority of our employees. Our contributions to the pension plan are based on periodic actuarial valuations. Our most recent actuarial valuation, covering the period January 1, 2004 to December 31, 2006 inclusive, was filed with the Financial Services Commission of Ontario in September 2004. Under this valuation, we are obligated to make annual cash contributions to the pension plan of approximately $80 million per year. The amount of the contributions that may be required after December 31, 2006 will depend on future investment returns, changes in benefits or actuarial assumptions.

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (The Society). As a result, in the case of future labour disputes we could face some degree of operational risk related to continued compliance with our license requirements of providing service to customers. We could also face financial risk related to our ability to negotiate collective agreements consistent with our rates. Existing collective agreements with the PWU and The Society expire in 2008.

Environmental Risk

We are subject to federal, provincial and municipal environmental regulations that are subject to change. Failure to comply could lead to government orders requiring us to take specific actions or could subject us to fines, penalties, or claims by third parties. Conducting environmental assessments and seeking government approvals for the construction of facilities could result in delays and cost increases.

Future changes in environmental regulations may result in material changes to the expenditure estimates used to calculate the carrying values of our environmental liabilities and associated regulatory assets. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet.

International scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to relocate some of our facilities, or face difficulties in locating and building new facilities.

RISK MANAGEMENT (continued)

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses on April 1, 1999 did not result in a transfer of title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Under the terms of our transfer orders, the OEFC will continue to hold these assets until we receive the federal and Indian band consents required for title transfer. After completion of title transfer, we expect our annual costs to exceed the amounts included in existing rate orders. If title transfer cannot be achieved, we expect that either the OEFC will continue to hold these assets or we will be required to relocate them, likely at significant expense. Such additional costs could have an adverse effect on our results of operations in the event we were unable to recover them in future rates.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2006 and 2007 would have an impact on net income of approximately $2 million in 2006 and $5 million in 2007.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of $40 million. The fair value of the swap contract is not significant.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2005 amounted to $430 million and principally relate to employee future benefits other than pension, the regulatory asset recovery account (RARA), environmental costs, pension costs and low-voltage services. We have also recorded regulatory liabilities amounting to $525 million as at December 31, 2005. These amounts pertain primarily to pension costs, export and wheeling fees and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for the employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARA, or if future OEB direction is judged to be probable. Most of the regulatory asset amounts have been reviewed by the OEB and confirmed as recoverable and any remaining balances will be reviewed as part of the OEB's 2006 review of our distribution business. If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs on an accrual basis are also disclosed in the notes to the financial statements. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 7.00% per annum is based on current expectations of long-term rates of return and reflects a pension asset mix consistent with the fund's investment policy of 57% held in equity securities, 38% held in corporate and government debt securities and 5% held in alternative assets consisting of hedge funds and private equity funds. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets exceeded this long-term assumption in 2005.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year-end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2005 have been reduced by 0.5% and 1.0%, varying by benefit plan, from those at December 31, 2004 in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

CRITICAL ACCOUNTING ESTIMATES (continued)

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in the service cost and interest cost of about $12 million per year.

Employee future benefits are included in labour costs and charged to results of operations or are capitalized as part of the cost of fixed assets. Changes in the assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2005. As a result of our review, we determined that the carrying value of our goodwill has not been impaired.

EMERGING ACCOUNTING PRONOUNCEMENTS

Canadian Accounting Standards Board's Strategic Plan

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with International Financial Reporting Standards over an expected five-year transitional period. The AcSB will develop and publish a detailed implementation plan for achieving convergence later in 2006. At the end of that period, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we will begin our transition preparations early.

Accounting for Rate Regulated Operations

The AcSB has an active project to review GAAP applicable to enterprises with rate-regulated operations. The first phase resulted in the issue of Accounting Guideline AcG-19, *Disclosures by Entities Subject to Rate Regulation*. Our disclosures reflect these new requirements. In the second phase of its project, the AcSB plans to review whether regulatory accounting treatments, which are commonly applied throughout our industry, meet the definition of an asset or liability as defined by Canadian Institute of Chartered Accountants (CICA) Handbook Section 1000, *Financial Statement Concepts*. If the AcSB concludes that they do not, we would be required to discontinue the application of rate-regulated accounting. Specifically, we would no longer be able to recognize our regulatory assets and liabilities, which amounted to $430 million and $525 million, respectively at December 31, 2005. As well, we may be required to account for payments in lieu of corporate income taxes related to our regulated business on a liability basis. The net effect of these changes would be charged to either retained earnings or results of operations once the new accounting standard became effective, dependent on the transition rules. At this time, it is uncertain what decision the AcSB will reach. However, we do not believe that the outcome of this project will have a material financial impact on our company.

Financial Instruments

During 2005, the AcSB completed its project on the recognition and measurement of financial instruments by issuing new recommendations dealing with financial instruments and hedging and by introducing the concept of other comprehensive income. Under the new accounting standards, which come into effect for our 2007 fiscal year, all financial instruments, including derivatives, must be included on a company's balance sheet and measured at fair value or, in limited circumstances when fair value may not be the most relevant basis, at cost or amortized cost. The standards also specify when gains and losses resulting from changes in fair value are to be recognized in the Statement of Operations. Existing requirements for hedge accounting are extended and clarified. In addition, certain gains and losses will be reported as other comprehensive income. We are assessing the overall impact of the new accounting standards, but do not believe that their application will have a material financial impact on our company.

Accounting for Conditional Asset Retirement Obligations

In December 2005, the Emerging Issues Committee (EIC) of the CICA issued EIC-159, *Conditional Asset Retirement Obligations*. This pronouncement governs the accounting for asset retirement obligations where the method or timing of disposal of an asset is conditional on some future event. The new pronouncement is effective for annual and interim periods ending after March 31, 2006. We have reviewed the new EIC pronouncement and do not expect that it will have a material impact upon our company.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a reporting issuer, we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. We completed our initial evaluation of our disclosure controls during the fourth quarter of 2005 and we anticipate completing our evaluation of our internal controls over financial reporting in 2006. Evaluations will continue to be conducted on an ongoing basis to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the consolidated financial statements for the year ended December 31, 2005, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been put in place, and that these controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

OUTLOOK

We will continue to concentrate on our top strategic priorities, which are to create and maintain an injury-free workplace with a concentrated focus on the elimination of serious injuries or close calls having the potential to cause serious injury; to further enhance the reliability of our transmission and distribution networks; and to improve our customers' levels of satisfaction. To these ends, we have renewed our focus on incident prevention and proactive applications, and we are making significant investments to address asset condition and improve reliability by maintaining and selectively increasing work program spending levels. In particular, we will ensure

OUTLOOK (continued)

that Ontario's needs for performance from our aging transmission system under tight generation supply conditions are met. Key transmission investment areas include assets critical to supporting generating stations and reducing congestion on the main transmission grid, such as key transformer station upgrades and high-voltage line replacements, and protection and control equipment replacements. Key distribution investment areas include vegetation management, increased wood pole replacements, feeder sectionalization and defect management, as well as customer care programs and the conservation and demand management program.

Consistent with our 10-year transmission plan, *Transmission Solutions 2005–2014*, we will make the necessary investments in our transmission infrastructure to ensure that growing area supply needs, and system configuration and reliability requirements, are successfully met. In particular, we intend to make area supply improvements in the Greater Toronto Area (including central Toronto and adjoining communities) as well as across Ontario. Further, we will complete the Niagara Reinforcement Project and we expect to undertake other reinforcement projects as the needs for transmission system investments are further identified by the OPA in its pending IPSP. As part of these initiatives, we will work closely with the OPA, the OEB, and other stakeholders, related or affected parties.

There is significant potential for the IPSP to include large scale transmission infrastructure investments not currently included within our investment plans. Examples include the Manitoba-Ontario high capacity lines, major new supply lines to Toronto, and new generation investment projects including those related to the retirement of coal-fired generation. Funding is also not included for the implementation of smart meters. We would need to reach agreements with all affected parties and have a reasonable expectation of recovery before proceeding with such large, complex undertakings.

The Province is continuing to examine the state of the electricity market and industry within Ontario. While we are not anticipating structural changes, such changes are possible, for example in the form of electricity distribution sector rationalization or as the result of municipal border dispute settlements. We will continue to work with the Government to assist them in their deliberations and will work cooperatively to implement any changes. In the interim, the Government expects us not to enter into further transactions involving the acquisition or divestment of LDCs or distribution assets.

With the amendments to the legislation affecting the electricity industry and the OEB's mandate, the approval for recovery of distribution regulatory assets in December 2004 and the anticipated distribution rate increases in 2006, we anticipate a stable regulatory environment for our distribution business going forward. However, the OEB has initiated a review of our revenue requirement for the transmission business and we are anticipating a decision in the first quarter of 2006 regarding a proposed earnings sharing mechanism. Given the need for transmission infrastructure across the province to ensure reliability and economic vitality, we proposed that any excess earnings subject to a sharing mechanism be utilized to fund these projects. We will prepare our regulatory evidence in the interest of all Ontarians.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

FORWARD LOOKING STATEMENTS AND INFORMATION

We have included forward-looking statements in this report that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. Any statement contained in this document that is not current or historical is a forward-looking statement. We have based these forward-looking statements on historical experience, current conditions and various assumptions believed to be reasonable in the circumstances. Actual results could differ materially from those projected in the forward-looking statements. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or otherwise.

This management's discussion and analysis is dated as at February 15, 2006. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 15, 2006.

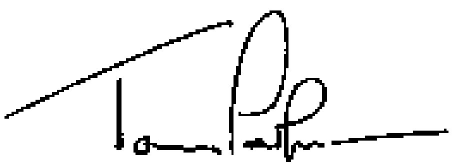
In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 54, outlines the scope of their examination and their opinion.

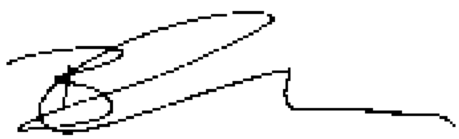
The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:



Tom Parkinson
President and Chief Executive Officer



Beth Summers
Chief Financial Officer

Executive Committee

Beth Summers
Chief Financial Officer

Tom Parkinson
President and Chief Executive Officer

Laura Formusa
General Counsel and Secretary

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2005 and December 31, 2004, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and December 31, 2004, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2005, in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 15, 2006

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Revenues		
Transmission *(Note 15)*	1,310	1,262
Distribution *(Notes 3 and 15)*	3,085	2,874
Other	21	17
	4,416	4,153
Costs		
Purchased power *(Notes 3 and 15)*	2,131	1,987
Operation, maintenance and administration	792	771
Depreciation and amortization *(Note 5)*	487	480
	3,410	3,238
Regulatory recovery *(Note 4)*	–	91
Income before financing charges and provision for payments in lieu of corporate income taxes	1,006	1,006
Financing charges *(Note 6)*	325	331
Income before provision for payments in lieu of corporate income taxes	681	675
Provision for payments in lieu of corporate income taxes *(Notes 7 and 15)*	198	177
Net income	483	498
Basic and fully diluted earnings per common share (Canadian dollars) *(Note 14)*	4,652	4,798

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Retained earnings, January 1	887	654
Net income	483	498
Dividends *(Note 14)*	(291)	(265)
Retained earnings, December 31	1,079	887

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2005	2004
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $18 million; 2004 - $18 million) *(Note 15)*	**622**	707
Materials and supplies	**56**	47
	678	754
Fixed assets *(Note 8)*:		
Fixed assets in service	**15,553**	14,940
Less: accumulated depreciation	**5,818**	5,475
	9,735	9,465
Construction in progress	**381**	348
	10,116	9,813
Other long-term assets:		
Deferred pension asset *(Note 12)*	**449**	534
Regulatory assets *(Note 9)*	**430**	443
Goodwill	**133**	133
Long-term accounts receivable and other assets	**20**	25
Deferred debt costs	**23**	23
	1,055	1,158
Total assets	**11,849**	11,725

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2005	2004
Liabilities		
Current liabilities:		
Bank indebtedness	**9**	9
Accounts payable and accrued charges *(Note 15)*	**700**	630
Accrued interest	**43**	44
Short-term notes payable *(Note 10)*	**–**	40
Long-term debt payable within one year *(Note 10)*	**589**	539
	1,341	1,262
Long-term debt *(Note 10)*	**4,466**	4,613
Other long-term liabilities:		
Regulatory liabilities *(Note 9)*	**525**	576
Employee future benefits other than pension *(Note 12)*	**716**	654
Environmental liabilities *(Note 13)*	**64**	74
Long-term accounts payable and accrued charges	**21**	22
	1,326	1,326
Total liabilities	**7,133**	7,201
Contingencies and commitments *(Notes 11, 17 and 18)*		
Shareholder's equity *(Note 14)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**1,079**	887
Total shareholder's equity	**4,716**	4,524
Total liabilities and shareholder's equity	**11,849**	11,725

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Rita Burak
Chair

Eileen Mercier
Chair, Audit and Finance Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Operating activities		
Net income	483	498
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	446	446
Amortization of discount	59	62
Low-voltage services	(24)	—
Retail settlement variance accounts	12	29
Regulatory recovery *(Note 4)*	–	(91)
	976	944
Changes in non-cash balances related to operations *(Note 16)*	194	(33)
Net cash from operating activities	1,170	911
Investing activities		
Capital expenditures	(691)	(727)
Other assets	9	19
Net cash used in investing activities	(682)	(708)
Financing activities		
Long-term debt issued	500	540
Long-term debt retired	(648)	(472)
Short-term notes payable	(40)	15
Dividends paid	(291)	(265)
Termination of interest rate swap	(10)	—
Other	1	7
Net cash used in financing activities	(488)	(175)
Net change in cash and cash equivalents	–	28
Cash and cash equivalents, January 1	(9)	(37)
Cash and cash equivalents, December 31 *(Note 16)*	(9)	(9)

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario). The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB will consider options to track net income excesses or deficiencies compared to approved returns for the period from January 1, 2006 until revised transmission rates are implemented. The options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. Current distribution rates are based on a cost of service rate regulation model, which also includes a targeted return of 9.88% on deemed common equity. In August 2005, Hydro One Networks filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for its distribution business. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting,

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 9.

On December 9, 2004, the OEB issued its decision on the prudence of various regulatory deferral accounts incurred prior to December 31, 2003, plus related interest. As a result of the OEB's decision, the proportion of our regulatory assets subject to potential future OEB disallowance has been significantly reduced. However, regulatory asset amounts included in approved accounts that were recognized after December 31, 2003 have not yet been reviewed by the OEB. Similarly, the Company's deferred distribution-related pension expenditures have not yet been reviewed by the OEB for prudency. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2005 amounted to $377 million (2004 - $318 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). 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 Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2005 – 6.8%; 2004 - 7.0%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Transmission	12 - 100	57
Distribution	15 - 75	41
Communication	7 - 40	21
Administration and service	5 - 50	41

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies (LDCs) in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Under Canadian Institute of Chartered Accountants Handbook Section 3062, *Goodwill and Other Intangible Assets*, goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Derivative Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations.

The Company does not engage in derivative trading or speculative activities.

Discounts, Premiums and Hedging

Discounts, premiums and hedging gains and losses are amortized over the period of the related debt.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. ELECTRICITY CREDITS TO CUSTOMERS

Under a new regulation issued in October 2005, Regulated Price Plan customers receive a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $140 million. The application of the one-time credit did not result in any adjustment to net income in the current or previously reported periods.

4. REGULATORY RECOVERY

The *Electricity Pricing, Conservation and Supply Act, 2002*, suspended a previously approved rate increase related to annual low-voltage services costs for embedded LDCs and direct customers. The associated costs are charged annually to the Company's results of operations. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002*, also allowed for establishment of a regulatory deferral account to record suspended low-voltage services amounts to be recovered from future customers. Due to uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 9, 2004 were not previously recognized as regulatory assets. Similarly, the Company did not reflect certain other costs, such as interest, as regulatory assets in prior years' financial statements.

On May 31, 2004, Hydro One applied for recovery of approximately $156 million included within various regulatory deferral accounts prior to December 31, 2003. The requested recovery primarily included the low-voltage services amounts not previously recognized as regulatory assets, as well as interest on all of the requested balances. As a result of the oral and written evidence submitted by Hydro One, the OEB issued a decision on December 9, 2004 regarding the prudence of the distribution-related deferral account balances included in the application. The OEB approved all but approximately $12 million of the requested amount for recovery over the period ending April 30, 2008. As a result of this successful regulatory recovery, the Company recorded an increase in its regulatory asset balance, which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue.

The 2004 regulatory recovery consisted of the following components:

Year ended December 31 (Canadian dollars in millions)	2004
Low-voltage services – 2002	17
Low-voltage services – 2003	25
Low-voltage services – 2004	23
Interest accretion	18
Other	8
	91

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	2005	2004
Depreciation of fixed assets in service	**369**	370
Fixed asset removal costs	**41**	34
Amortization of regulatory and other assets	**77**	76
	487	480

6. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	2005	2004
Interest on short-term notes payable	**1**	1
Interest on long-term debt payable	**297**	286
Amortization of discount	**58**	62
Other	**5**	7
Less: Interest capitalized on construction in progress	**(21)**	(23)
Interest capitalized on regulatory assets	**(10)**	—
Interest earned on investments	**(5)**	(2)
	325	331

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004
Income before provision for PILs	681	675
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	246	244
(Decrease) increase resulting from:		
Net temporary differences:		
Pension contribution in excess of pension expense	(25)	(23)
Subsidiary loss carryforward	(21)	—
Regulatory recovery	–	(33)
Interest capitalized for accounting purposes but deducted for tax purposes	(11)	(8)
Employee future benefits other than pension expense in excess of cash payments	8	9
Environmental expenditures	(5)	(6)
Capital cost allowance less than (in excess of) depreciation and amortization	1	(7)
Other	(9)	(9)
Net temporary differences	(62)	(77)
Permanent differences:		
Large corporations tax	13	16
Other	1	(6)
Net permanent differences	14	10
Provision for PILs	198	177
Effective income tax rate	29.07%	26.22%

In May 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to access the subsidiary's accumulated tax losses and a future tax asset of approximately $21 million was recognized in the second quarter. As at December 31, 2005, approximately $9 million of this amount remains available for use in 2006.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2005, future income tax liabilities of $265 million (2004 - $224 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized on an accrual basis rather than under the taxes payable method. As a result, the provision for PILs would have been higher by approximately $41 million.

8. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2005				
Transmission	8,124	2,889	239	5,474
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	—	421
	15,553	**5,818**	**381**	**10,116**
2004				
Transmission	7,833	2,753	249	5,329
Distribution	5,066	1,884	55	3,237
Communication	744	309	31	466
Administration and service	816	471	13	358
Easements	481	58	—	423
	14,940	5,475	348	9,813

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $21 million in 2005 (2004 - $23 million).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities (see Notes 2 and 4):

December 31 (Canadian dollars in millions)	2005	2004
Regulatory assets:		
Employee future benefits other than pension	**126**	168
Regulatory asset recovery account	**88**	121
Environmental	**79**	89
Pension	**76**	34
Low-voltage services	**53**	26
Other	**8**	5
Total regulatory assets	**430**	443
Regulatory liabilities:		
Deferred pension	**449**	534
Export and wheeling fees	**32**	19
Retail settlement variance accounts	**30**	14
Other	**14**	9
Total regulatory liabilities	**525**	576

9. REGULATORY ASSETS AND LIABILITIES (continued)

Regulatory assets

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 3 years (2004 - 4 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately $42 million.

Regulatory asset recovery account (RARA)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by Hydro One in its May 31, 2004 application (see Note 4). Recoverable amounts represent balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately $20 million. In addition, related financing charges would have been higher by $7 million.

Environmental

Hydro One provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower and operation, maintenance and administration expense would have been higher by $14 million. During 2004, the Company identified an increased risk associated with potential offsite migration of contamination in storm water run-off from some of its transmission sites. Given the need to address this issue, in 2004 the Company adjusted its future land assessment and remediation expenditure estimate and increased its regulatory asset and offsetting environmental obligation by approximately $16 million (see Note 13). The OEB has the discretion to examine and assess the prudence and the timing of recovery of Hydro One's future regulatory expenditures.

Pension

In a July 14, 2004 decision, the OEB approved the Company's establishment of a regulatory account to record the Company's distribution-related pension contributions that would otherwise have been charged to results of operations. The regulatory asset also includes amounts payable to Inergi LP (Inergi) commencing in 2005 in respect of a risk sharing agreement related to the imbalance between pension fund assets and liabilities in respect of transferred staff (see Note 18). In its decision, the OEB concluded that prudently incurred expenditures of this type are generally recoverable as part of a general rate application. The Company has included a request for recovery as part of its distribution rate application currently under review by the OEB.

Low-voltage services

The OEB's December 9, 2004 decision allows for delayed recovery of previously approved low-voltage system amounts, within the RARA, for the period up to December 31, 2003. Given this decision, the Company has determined that it is probable that, at some future date, the OEB will also approve recovery of the low-voltage amounts attributable to 2004 and 2005, plus interest. As a result, the Company has recognized a regulatory asset reflecting this probable future recovery.

Regulatory liabilities

Deferred pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid to the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately $38 million, assuming no regulatory deferral of distribution and Inergi pension-related amounts. In addition, related financing charges would have been higher by $4 million.

Export and wheeling fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MW on electricity exported outside of Ontario. The Company expects that amounts collected in respect of this export and wheeling fee, plus interest, will be taken into consideration by the OEB in assessing the revenue requirement of our transmission business as part of the Company's next general transmission rate application.

Retail settlement variance accounts

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allows for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA. The Company anticipates that OEB will include the net balance of this regulatory account in future rates.

10. DEBT

December 31 (Canadian dollars in millions)	2005	2004
Short-term notes payable	–	40
Long-term debt:		
6.94% debentures due 2005	–	200
4.00% notes due 2005	–	339
4.10% notes due 2006[1]	–	109
4.15% notes due 2006	**280**	280
4.20% notes due 2006	**168**	168
4.30% notes due 2006	**141**	141
4.45% notes due 2007	**282**	282
4.55% notes due 2007	**73**	73
4.10% notes due 2007[2]	**40**	40
4.00% notes due 2008	**500**	500
3.95% notes due 2009	**400**	250
7.15% debentures due 2010	**400**	400
6.40% notes due 2011	**250**	250
5.77% notes due 2012	**600**	600
7.35% debentures due 2030	**400**	400
6.93% notes due 2032	**500**	500
6.35% notes due 2034	**385**	385
5.36% notes due 2036	**350**	—
6.59% notes due 2043	**315**	315
	5,084	5,232
Less: Long-term debt payable within one year	**(589)**	(539)
Net unamortized discounts	**(14)**	(73)
Unamortized hedging losses	**(15)**	(7)
Long-term debt	**4,466**	4,613

[1] 4.10% notes due 2006 were redeemed on December 16, 2005.

[2] Step-up coupon, after year 3 from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company’s commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2004, the notes had a weighted-average interest rate of 2.3%.

Hydro One has a $750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2006, with a two-year extension option. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's commercial paper program.

The Company issues notes for long-term financing under the medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which the full amount is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2005, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures (Canadian dollars in millions)	Weighted Average Interest Rate (%)
1 year	589	4.2
2 years	395	4.4
3 years	500	4.0
4 years	400	4.0
5 years	400	7.2
	2,284	4.7
6 – 10 years	850	6.0
Over 10 years	1,950	6.6
	5,084	5.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year-end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2005		2004	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**5,084**	**5,697**	5,232	5,658

[1] The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into forward fixed interest rate swap agreements or forward sale agreements of Government of Canada bonds to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2004, Hydro One entered into a forward interest rate swap agreement with a notional principal amount of $100 million to lock in the interest rate of a future issuance planned for 2005. In 2005, Hydro One entered into an additional forward interest rate swap agreement to lock in a further $50 million in notional principal. During 2005, the Company terminated both forward interest rate agreements for a net cash payment of $10 million that is being amortized on an annuity basis over the thirty-year term of the related debt.

As at December 31, 2005, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of $40 million.

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2005 (2004 - $nil).

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2005, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2005, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

12. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Allocation

Hydro One's pension plan asset allocation at December 31, 2005 and 2004 was as follows:

	% of Plan Assets	
December 31	**2005**	2004
Equity securities	**60.6**	59.2
Debt securities	**36.2**	36.2
Other	**3.2**	4.6
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities in the Province of $79 million and $83 million at December 31, 2005 and 2004 respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, the Company contributed $83 million to its pension plan in respect of 2005 (2004 - $74 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation date no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2005, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $123 million in 2005 (2004 - $110 million).

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2005**	2004	**2005**	2004
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**4,862**	4,323	**966**	897
Current service cost	**83**	76	**26**	24
Interest cost	**277**	254	**57**	54
Benefits paid	**(248)**	(232)	**(40)**	(36)
Plan amendments	**–**	—	**1**	—
Net actuarial loss	**381**	441	**133**	27
Accrued benefit obligation, December 31	**5,355**	4,862	**1,143**	966
Change in plan assets				
Fair value of plan assets, January 1	**4,243**	3,939	**–**	—
Actual return on plan assets	**630**	458	**–**	—
Benefits paid	**(248)**	(232)	**–**	—
Employer's contributions[1]	**83**	74	**–**	—
Employees' contributions	**16**	16	**–**	—
Administrative expenses	**(11)**	(12)	**–**	—
Fair value of plan assets, December 31	**4,713**	4,243	**–**	—
Funded status				
(Unfunded benefit obligation)	**(642)**	(619)	**(1,143)**	(966)
Unamortized net actuarial losses	**1,069**	1,128	**385**	271
Unamortized past service costs	**22**	25	**6**	6
Deferred pension asset (accrued benefit liability)	**449**	534	**(752)**	(689)
Less: current portion	**–**	—	**36**	35
Deferred pension asset (long-term liability)	**449**	534	**(716)**	(654)

[1] In January, 2006, the Company made a contribution of $8 million in respect of 2005 (2005 - $7 million in respect of 2004).

12. EMPLOYEE FUTURE BENEFITS (continued)

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	2005	2004	2005	2004
Components of net periodic benefit cost				
Current service cost, net of employee contributions	67	60	26	24
Interest cost	277	254	57	54
Actual return on plan asset net of expenses	(619)	(446)	–	—
Actuarial loss	381	441	133	27
Other	–	—	–	(1)
Costs arising in the period	106	309	216	104
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	327	174	–	—
Actuarial gain	(268)	(362)	(113)	(11)
Plan amendments	3	3	–	1
Net periodic benefit cost[2]	168	124	103	94
Charged to results of operations[2]	23	22	64	56
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	–	—	171	124
Service cost and interest cost	–	—	12	11
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	–	—	(133)	(108)
Service cost and interest cost	–	—	(10)	(9)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	7.00%	7.00%	–	—
Weighted-average discount rate	5.75%	6.00%	5.93%	6.18%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.75%	2.25%	2.75%	2.25%
Average remaining service life of employees (years)	10	12	10	11
Rate of increase in health care cost trend[3]	–	—	4.40%	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	5.00%	5.75%	4.98%	5.93%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.75%	2.50%	2.75%
Rate of increase in health care cost trend[4]	–	—	4.40%	4.40%

[2] The Company follows the cash basis of accounting. During 2005, pension costs of $83 million (2004 - $81 million) were attributed to labour, of which $23 million (2004 - $22 million) was charged to operations, $32 million (2004 - $31 million) was capitalized as part of the cost of fixed assets, and $28 million (2004- $28 million) was attributed to a regulatory asset.

[3] 8.47% in 2005 grading down to 4.40% per annum in and after 2014 (2004 – 9.00% in 2004 grading down to 4.40% per annum in and after 2014).

[4] 7.87% in 2006 grading down to 4.40% per annum in and after 2014 (2004 – 8.47% in 2004 grading down to 4.40% per annum in and after 2014).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	2005	2004
Environmental liabilities, January 1	**89**	83
Interest accretion	**5**	5
Expenditures	**(14)**	(15)
Revaluation adjustment *(Note 9)*	**(1)**	16
Environmental liabilities, December 31	**79**	89
Less: current portion	**(15)**	(15)
	64	74

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - $15 million; 2007 - $14 million; 2008 - $12 million; 2009 - $10 million; 2010 - $9 million; and thereafter - $40 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

14. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25.00 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2005, preferred dividends in the amount of $18 million (2004 - $18 million) and common dividends in the amount of $273 million (2004 - $247 million) were declared.

14. SHARE CAPITAL (continued)

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

15. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2005 includes $1,276 million (2004 - $1,228 million) related to these services.

Hydro One received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2005 includes $21 million (2004 - $21 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2005 includes $127 million related to this program. In 2004, the Company also received $127 million for rural rate protection, of which $1 million was paid to LDCs in respect of annexation agreements.

In 2005, Hydro One purchased power in the amount of $2,095 million (2004 - $1,951 million) from the IESO administered electricity market and $36 million (2004 - $36 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2005, Hydro One incurred $7 million (2004 - $10 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $11 million (2004 - $11 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2005 and 2004.

The provision for payments in lieu of corporate income taxes was paid or payable to OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2005	2004
Accounts receivable	**116**	120
Accounts payable and accrued charges	**(263)**	(247)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $213 million (2004 - $200 million).

16. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the consolidated statements of cash flows, “cash and cash equivalents” refers to the balance sheet item “bank indebtedness.”

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2005	2004
Accounts receivable decrease (increase)	**85**	(91)
Materials and supplies increase	**(9)**	(2)
Accounts payable and accrued charges increase	**70**	10
Accrued interest (decrease) increase	**(1)**	6
Long-term accounts payable and accrued charges decrease	**(1)**	(9)
Employee future benefits other than pension increase	**62**	57
Other	**(12)**	(4)
	194	(33)
Supplementary information:		
Interest paid	**300**	285
Payments in lieu of corporate income taxes	**210**	207

17. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have an adverse effect on the Company’s consolidated financial position, results of operations or cash flows.

As a result of Hydro One’s acquisition of certain transmission, distribution and energy services assets, liabilities, rights and obligations of Ontario Hydro, Hydro One has succeeded Ontario Hydro as a party in a number of legal proceedings. On September 1, 1995, Torcom Communications Inc. (Torcom) named Ontario Hydro as one of several defendants in a suit seeking damages of $150 million, as well as specific performance of certain agreements and interim injunctive relief. Torcom had sought to purchase certain telecommunication devices belonging to a bankrupt company from the court-appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995, when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not yet served a statement of defence. Hydro One believes that there are strong defences to the plaintiff’s claims against Ontario Hydro and that it is unlikely that the outcome of the litigation will have a material adverse effect on its business, results of operations, financial position or prospects. Torcom has not proceeded with this claim for almost ten years.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG

17. CONTINGENCIES (continued)

and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty, and compensation for costs incurred in the course of prior negotiations of band grievances with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. This case was consolidated with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

18. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period. The initial service level price ranges between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2005, and in total thereafter are as follows: 2006 - $110 million; 2007 - $108 million, 2008 - $97 million; 2009 - $93 million; 2010 - $90 million; and thereafter - $102 million.

Additionally, the outsourcing agreement with Inergi includes a risk sharing agreement involving either Hydro One or Inergi making a payment related to a past imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement was settled based on data available on December 31, 2004, reflecting economic factors and pension fund rates of return. Hydro One is required to pay Inergi approximately $17 million equally over the next two years.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2005, the Company provided prudential support, using a combination of bank letters of credit of $21 million (2004 - $33 million) and parental guarantees of $275 million (2004 - $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2005, Hydro One had bank letters of credit of $82 million (2004 - $80 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - $5 million; 2007 - $4 million; 2008 - $4 million; 2009 - $4 million; 2010 - $nil; and thereafter - $nil.

19. SEGMENT REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business. Hydro One is currently in the process of assessing its strategy with respect to these operations.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2005				
Segment profit				
Revenues	**1,310**	**3,085**	**21**	**4,416**
Purchased power	**–**	**2,131**	**–**	**2,131**
Operation, maintenance and administration	**353**	**413**	**26**	**792**
Depreciation and amortization	**246**	**236**	**5**	**487**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**711**	**305**	**(10)**	**1,006**
Financing charges				**325**
Income before provision for payments in lieu of corporate income taxes				**681**
Capital expenditures	**349**	**338**	**4**	**691**
2004				
Segment profit				
Revenues	1,262	2,874	17	4,153
Purchased power	—	1,987	—	1,987
Operation, maintenance and administration	356	392	23	771
Depreciation and amortization	241	234	5	480
Income (loss) before financing charges, provision for payments in lieu of corporate income taxes and regulatory recovery	665	261	(11)	915
Regulatory recovery				91
Income before financing charges and provision for payments in lieu of corporate income taxes				1,006
Financing charges				331
Income before provision for payments in lieu of corporate income taxes				675
Capital expenditures	432	288	7	727

December 31 (Canadian dollars in millions)	2005	2004
Total assets		
Transmission	**6,832**	6,785
Distribution	**4,925**	4,845
Other	**92**	95
	11,849	11,725

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	2005	2004	2003	2002	2001
Statement of operations data					
Revenues					
Transmission	**1,310**	1,262	1,298	1,317	1,259
Distribution	**3,085**	2,874	2,734	2,682	2,158
Other	**21**	17	26	32	49
	4,416	4,153	4,058	4,031	3,466
Costs					
Purchased power	**2,131**	1,987	1,872	1,858	1,267
Operation, maintenance and administration[1]	**792**	771	795	832	824
Depreciation and amortization	**487**	480	454	411	384
	3,410	3,238	3,121	3,101	2,475
Regulatory recovery[2]	**–**	91	—	—	—
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,006**	1,006	937	930	991
Financing charges	**325**	331	348	353	350
Income before provision for payments in lieu of corporate income taxes	**681**	675	589	577	641
Provision for payments in lieu of corporate income taxes	**198**	177	193	233	267
Net income	**483**	498	396	344	374
Basic and fully diluted earnings per common share *(Canadian dollars)*	**4,652**	4,798	3,779	3,258	3,562
December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**6,832**	6,785	6,589	6,638	6,693
Distribution	**4,925**	4,845	4,623	4,694	4,416
Other	**92**	95	94	90	122
Total assets	**11,849**	11,725	11,306	11,422	11,231
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,341**	1,262	1,192	1,894	1,625
Long-term debt	**4,466**	4,613	4,539	3,938	4,079
Other long-term liabilities	**1,326**	1,326	1,284	1,451	1,533
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,079**	887	654	502	357
Total liabilities and shareholder's equity	**11,849**	11,725	11,306	11,422	11,231

Year ended December 31 (Canadian dollars in millions)	**2005**	2004	2003	2002	2001
Other financial data					
Capital expenditures					
Transmission	**349**	432	289	260	274
Distribution[3]	**338**	288	292	286	247
Other	**4**	7	16	24	45
Total capital expenditures	**691**	727	597	570	566
Ratios					
Net asset coverage on long-term debt[4]	**1.93**	1.88	1.86	1.90	1.88
Earnings coverage ratio[5]	**2.69**	2.70	2.43	2.35	2.53
Operating statistics					
Transmission					
Units transmitted *(TWh)*[6]	**157.0**	153.4	151.7	153.2	146.9
Ontario 20-minute system peak demand *(MW)*[6]	**26,219**	25,204	24,849	25,629	25,269
Ontario 60-minute system peak demand *(MW)*[6]	**26,160**	24,979	24,753	25,414	25,239
Total transmission lines *(circuit-kilometres)*	**28,547**	28,643	28,621	28,492	28,387
Distribution					
Units distributed to Hydro One customers *(TWh)*[6]	**29.7**	28.5	27.9	27.1	21.3
Units distributed through Hydro One lines *(TWh)*[6,7]	**45.6**	44.8	44.7	45.1	41.3
Total distribution lines *(circuit-kilometres)*	**122,118**	121,736	121,285	120,767	120,448
Customers	**1,273,768**	1,258,925	1,238,748	1,219,614	1,193,089
Total regular employees	**4,189**	4,118	3,967	3,933	4,815

[1] Operation, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program.

[2] As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

[3] Capital expenditures exclude $468 million in 2001 associated with acquisitions of LDCs.

[4] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[5] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[6] System related statistics include preliminary figures for December.

[7] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO. Prior to Open Access in 2002, these consumers purchased power directly from the predecessor of OPG.

SENIOR MANAGEMENT TEAM

Tom Parkinson
President and
Chief Executive Officer

Laura Formusa
General Counsel and
Secretary

Geoff Ogram
Vice-president,
Strategy and Development

Wayne Smith
Vice-president,
Grid Operations

Steve Dorey
Vice-president,
External Relations

Peter Gregg
Vice-president, Executive office
and Corporate Communications

Nairn McQueen
Vice-president,
Engineering and
Construction Services

Rick Kellestine
Vice-president,
Culture

Myles D'Arcey
Senior Vice-president,
Customer Operations

Beth Summers
Chief Financial Officer

John Fraser
Vice-president,
Internal Audit and
Chief Risk Officer

Tom Goldie
Senior Vice-president,
Corporate Services

BOARD OF DIRECTORS

Rita Burak
Chair of the Board of Directors,
Hydro One Inc.

Sami Bébawi
Executive Vice President,
Office of the President,
President, Socodec Inc.,
SNC–Lavalin Group Inc.

Murray J. Elston
President and CEO, Canadian
Nuclear Association

Don MacKinnon
President,
Power Workers' Union

Eileen A. Mercier
Corporate Director

Walter Murray
Corporate Director

Kathleen O'Neill
Corporate Director

Tom Parkinson
President and CEO,
Hydro One Inc.

Hon. Bob Rae
Partner, Goodmans LLP

Douglas E. Speers
Chairman and Director,
Emco Corporation

Kenneth D. Taylor
Chair, Taylor and Ryan Inc.

Blake Wallace, Q.C.
Vice President and Director,
Murray & Company

W. Geoffrey Beattie
President, The Woodbridge
Company Limited
Resigned November 10, 2005

Dr. Murray B. Frum
Chair and CEO,
Frum Development Group
Resigned September 29, 2005

Adam Zimmerman
Coporate Director
Resigned July 18, 2005

BOARD COMMITTEES

Audit and Finance Committee

The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met four times in 2005.

Members: Eileen Mercier, *Chair*. Murray Elston, Walter Murray, Kathleen O'Neill, Douglas Speers

Corporate Governance Committee

The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandates of each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2005.

Members: Blake Wallace, *Chair*. Rita Burak, Eileen Mercier, Hon. Bob Rae

Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met seven times in 2005.

Members: Hon. Bob Rae, *Chair*. Walter Murray, Kathleen O'Neill, Blake Wallace

Regulatory and Environment Committee

The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met five times in 2005.

Members: Murray Elston, *Chair*. Sami Bébawi, Don MacKinnon, Kenneth Taylor, Blake Wallace

Health and Safety Committee

The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2005.

Members: Don MacKinnon, *Chair*. Sami Bébawi, Douglas Speers, Kenneth Taylor

COPORATE INFORMATION

Corporate Address

483 Bay Street
Toronto, Ontario
M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations

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investor.relations@HydroOne.com

Media Inquiries

(416) 345-6868
1-877-506-7584

Customer Inquiries

Power outage and emergency number:
1-800-434-1235

Residential, farm & small business accounts:
1-888-664-9376

Business accounts: 1-877-447-4412

Auditors

Ernst & Young LLP

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Hydro One Inc.

483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Putting power to work

Hydro One Annual Report 2006

hydro One

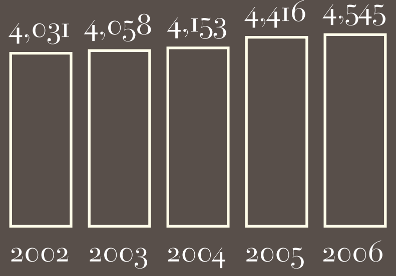
Consolidated financial

highlights and statistics

Year ended December 31 (Canadian dollars in millions)	2006	2005	Change	% Change
Revenues	**4,545**	4,416	129	3
Purchased power	**2,221**	2,131	90	4
Operating costs	**1,395**	1,279	116	9
Net income	**455**	483	(28)	(6)
Net cash from operations	**896**	1,169	(273)	(23)
Average annual Ontario 60-minute peak demand *(MW)*[1]	**22,650**	23,074	(424)	(2)
Distribution – units distributed to our customers *(TWh)*[1]	**29.0**	29.7	(0.7)	(2)

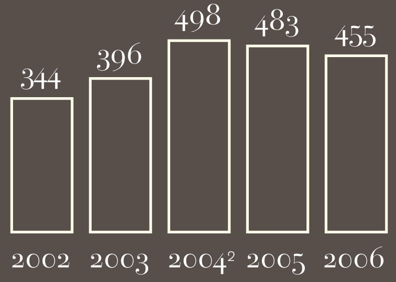
1 System-related statistics include preliminary figures for December.

Revenues
(Cdn $ millions)



Total Assets
December 31, 2006
(Cdn $ millions)

Net Income
(Cdn $ millions)



2 Net income for 2004 includes a one-time regulatory recovery of $91 million.

The Hydro One Family of Companies

Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom. The subsidiaries are necessary to meet legislative and regulatory requirements.

Hydro One Networks Inc.
Represents the significant majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers and represents less than 1% of our total assets.

Our power at work

Customer satisfaction continued to climb in 2006, with

86%

of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

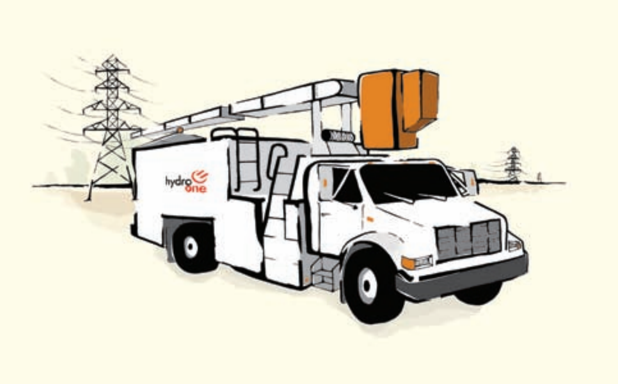
The North American Electric Reliability Council (NERC) awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

During a two-month period, three intense storms tested Ontario and knocked out power to more than 400,000 of our customers. The excellence of our restoration efforts earned us a prestigious *Emergency Recovery Award* from the Edison Electric Institute. This is the first time this award has gone to a utility based outside of the United States.

The Ontario Energy Board approved an increase of approximately

$160M

in our annual distribution revenue requirement. This decision demonstrates the OEB's confidence in our ability to maintain and operate Ontario's electricity system. The increased funds will enable us to make important investments we need in our distribution system.



Message from our Chair, Rita Burak

Ensuring that Ontario continues to have the electricity delivery system that it needs and deserves.

This year, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, expertly meeting the operational challenges posed by multiple severe storms that affected many of our customers. The company embarked on several large projects to ensure the delivery of safe, reliable electricity to the people of Ontario.

The company's net income in 2006 decreased by $28 million, or 6%, to $455 million compared to 2005. This decrease primarily reflects increased expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, and lower transmission tariff revenues resulting from lower demand and changes to transmission regulations.

As Chair of Hydro One, I understand that the good governance of Hydro One is essential to our shareholder, the Province of Ontario, our bond holders and the people of Ontario who depend upon Hydro One's electricity delivery system. Hydro One was focused on new securities regulations this year and is now fully compliant with the strict new financial control and disclosure requirements.

We take our financial obligations seriously and our financial controls and disclosure practices are solid and undergo regular external scrutiny. We operate in a highly transparent manner. Hydro One has embraced all 13 recommendations of Ontario's Auditor General to improve compliance with our internal policies and procedures.

Hydro One made critical investments both in transmission and in distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Hydro One spent $1.7 billion in 2006 in total capital and operation, maintenance and administrative expenditures.

Our ability to arrange sufficient and cost-effective financing supports our improving long-term credit rating. This is vital to our ability to refinance maturing debt, fund capital expenditures and address other requirements. In particular, Hydro One has access to long-term funding that better matches our debt to our long-lived assets. The upgrades to our credit ratings reflect the confidence of the rating agencies and investors in the performance and management of the company.

The Board expects continued strong, stable financial performance and is confident in the management team's ability to meet the challenges in the coming year. In the past two years Hydro One has begun a major new construction phase and this will continue in the years ahead. Major projects vital to the economic well-being of Ontario are underway, including a new interconnection with Quebec, transmission upgrades in Toronto and the connection of new sources of generation as they become available across Ontario.

Hydro One paid its shareholder, the Province of Ontario, dividends of $350 million. Hydro One recorded $179 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province.

On behalf of the Board of Directors, I would like to thank Hydro One's management and employees for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.

R. Burak

Rita Burak
Chair

Message from our President and CEO (Acting), Laura Formusa

Our work is complex, but the reason we do it is simple: Ontario depends upon Hydro One to deliver the electricity needed to put power to work.

Hydro One exists to ensure that the people, businesses, industries and communities of Ontario have the electricity they need to put power to work for them. Our transmission system represents more than 96% of Ontario's capacity.

We understand that our customers and other stakeholders expect Hydro One to be managed in a responsible manner, respecting the public trust placed in us to ensure the safe and reliable delivery of electricity at reasonable cost.

We take this trust seriously and believe that our performance and achievements of this past year bear this out.

Serving our customers drives everything we do. And our customers are diverse. From industrial giants like mining company Inco, Ontario's largest electricity consumer, to greenhouse operations in Leamington, to summer camps in Deep River and family homes in every corner of the province, we deliver electricity to a wide range of consumers.

In 2006, our customers told us that our service was better than ever. We made an honest appraisal of how we could do a better job of meeting our customers' needs, which enabled us to make major advances in improving our relationships. We have seen double-digit increases in customer satisfaction levels and we aim to reach customer satisfaction levels of 90%, on average, across all customer segments.

NERC gave our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The report singled out our industry-leading physical security procedures, infrastructure and program management as well as our innovative and fully integrated, multi-functional communications system.

We became the first utility based outside of the United States to receive the prestigious Edison Electric Institute *Emergency Recovery Award* recognizing the company's outstanding efforts in restoring power to more than 400,000 customers following three severe storms.

Our financial performance in 2006 was strong, with a net income of $455 million, and we paid our shareholder a healthy dividend.

As stewards of this province's massive and complex electricity transmission and delivery systems, we made significant progress on a number of critical system investment initiatives. We signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems. This $124 million investment will add an important new connection between the two grids and increase Ontario's ability to access electricity generated through renewable resources.

In November 2006, construction crews restored the Ontario to Michigan interconnection in the Sarnia area with the transmission operator in Michigan. This interconnection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of the existing high-voltage transmission system. This circuit will increase our import and export capacity by about 400MW and 200MW respectively.

We completed the excavation of a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative $45 million investment will carry an array of electricity transmission lines to tie the east and west sides of the city together with minimal disruption. This work will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

In 2006, we launched several new conservation and demand management programs in line with the Province's goal to create a culture of conservation in Ontario. Our programs mirror our customer base; some help Ontario families save electricity and money, while others use innovative technology to allow our larger customers to ease strain on the provincial electricity grid during peak demand periods.

While we're proud of our accomplishments, our main focus is on the challenges facing Ontario's electricity transmission system. Meeting these challenges by constructing the necessary transmission infrastructure will require cooperation with all of our stakeholders.

As guardians of the province's electricity transmission system, we have a number of key investment initiatives that require our utmost attention in the year ahead. Most significant of those initiatives is the proposed construction of a new 500-kV transmission line to deliver additional electricity to southern Ontario. We are undertaking consultations with the public and other interested groups about the routing of the line as well as its benefits and impacts.

We will continue to seek approvals for a number of other major projects which are geared to improving the reliability of supply to local areas within Ontario.

My management team and I will continue to ensure that Hydro One works efficiently, effectively and in the best interests of the people of Ontario. I am enthusiastic about the challenges that lie ahead of us and proud of our record of past achievements.

I'd like to thank Hydro One's employees for working safely and with the utmost commitment to our customers. We rely on the work our employees do every day to make sure that the people of Ontario can put power to work.

Laura Formusa
President and Chief Executive Officer (Acting)

Stephanie Oatway, Energy Analyst, CVRD Inco, Sudbury

Power on demand

"Power is useless unless it is there when you need it. That is why reliable transmission is so critical to our business," says Stephanie Oatway, Energy Analyst, CVRD Inco.

When Ontario's largest single-point electricity user speaks, Hydro One listens. Every year Inco's Ontario operations represent about ¾ of 1% of Ontario's total electricity consumption. How much is that? 1,400 Gigawatt hours, enough to power a city the size of Barrie.

While Inco generates about 20% of the electricity that it needs, it depends on the reliability of Hydro One's transmission system to keep it operating safely and profitably. With as many as 2,000 people working as far as two kilometres underground, having a secure, stable source of electricity is a serious matter.

And with today's on-demand supply management systems and the booming nickel market, losing time to electricity failures is unacceptable.

Stephanie Oatway is responsible for making sure Inco has the electricity it needs to produce the 275 million pounds of nickel per year plus copper and other precious metals. As a representative of our largest customer, she is in constant contact with Hydro One to make sure we deliver on our promises.

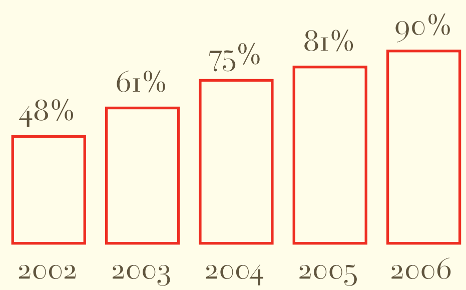
Last year our customers, big and small, told us we were doing better than ever on communicating and meeting our commitments to them.

275

MILLION POUNDS,

the amount of nickel Inco's Sudbury operations produce per year.

Large Industrial Customer Satisfaction



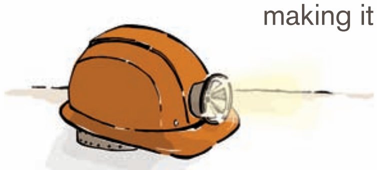
Customer satisfaction continued to climb in 2006, with 86% of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

Transmission reliability is a big reason our customers are more satisfied than ever before. The North American Electric Reliability Council awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's extensive audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

Hydro One's senior management team devotes time and energy to getting to know our Large Customers' businesses. Each member of the senior management team has direct relationships with our customers. They meet on a regular basis and are available any time if a customer has a question or an issue.

"Hydro One's people have taken the time to understand our business and they know what's at stake for us. They get it," Oatway says.

Inco uses 1,400 Gigawatt hours of electricity per year to power its operations – making it Ontario's largest single-point user.



Camp Lau-Ren, Deep River

The buzz of camp

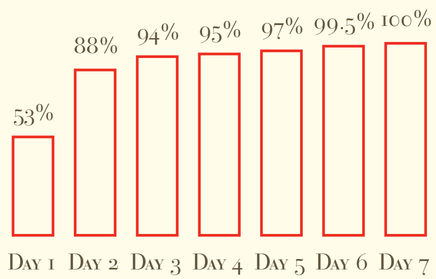
Shortly after dinner on July 17, dark clouds filled the sky over Camp Lau-Ren on the edge of the Ottawa River.

"The winds came right through the camp toppling trees and knocking down power lines. It was a matter of seconds and the power was out," says Nicky Nel, a volunteer counsellor for the last 15 years with Camp Lau-Ren. "We rushed around and made sure everyone was safe and after it was all done our first question was, 'Can camp happen without electricity?'"

The campers at Camp Lau-Ren weren't the only people asking that question.

Across Ontario, 170,000 Hydro One customers lost electricity. With tens of thousands of trees down, more than a thousand power poles broken and hundreds of kilometres of electricity line buried beneath trees snapped like matchsticks, it was the worst damage we'd seen since the 1998 Ice Storm. It would be more than a week until everyone had their power back on.

Storm Recovery
(Percentage of 170,000 affected customers restored)



120 KM/h

winds during three major storms and eight tornadoes pounded Ontario in the summer of 2006.

Hydro One responded to this storm by mobilizing our highly trained workforce, bringing in partners from other utilities and working long days to safely return electricity service to our customers. Our fleet of helicopters filled the sky and crews worked tirelessly to rebuild Ontario's electricity delivery system. In the first 24 hours, we restored electricity to 90,000 of the customers that had been affected.

For our work on this storm and two others in a two-month period, the Edison Electric Institute awarded Hydro One the *Emergency Recovery Award*, the first time this honour has been bestowed on a utility based outside of the United States.

While recognition from our peers as one of the best in the business at storm recovery means a lot, it pales in comparison to the way our customers responded. After four days of sharing two outhouses between 60 people, with no electricity, no flush toilets, no electric lights and no running water, Hydro One trucks were treated to a hero's welcome when they finally pulled into Lau-Ren.

"When we saw the trucks, we knew Hydro One had reached us," Nicky says. "The campers were yelling and greeting them with signs. It was a great moment. I think for a lot of the campers, they had a whole new appreciation for electricity."

Hydro One deployed more than 1,000 workers, who worked 16-hour days to restore electricity and repair the worst damage since the 1998 Ice Storm.

Cole Cacciavillani of CF Group Greenhouses, Leamington

Green power blooms

Keeping a greenhouse's climate at the perfect temperature and humidity depends upon electricity. The summer heat inside the greenhouse is so great that without the electric fans, the plants would never survive to bloom. During Ontario's coldest months, without electricity there'd be no flowers for Valentine's Day.

Backup electricity generation for Ontario's greenhouse industry is truly a matter of life and death.

"If we lose power, we're out of business," says Cole Cacciavillani, whose father Floyd started the family business with a single greenhouse in the 1950s.

In the last decade, CF Group Greenhouses (CF Group) has grown enough potted plants to cover Ontario. It's also developed generator technology to help greenhouses and other critical electricity users meet their own urgent power needs.

"All greenhouses invest in backup generation, but we only need it in emergencies. With help from Hydro One, we've connected that generation to the grid to put it to work for the rest of Ontario," says Cacciavillani.

Working with Hydro One, Cacciavillani has connected close to 4 MW of power that Ontario can call on when it needs more supply. The connection contributes to Ontario's supply reliability, takes stress off of Hydro One's transmission system and helps Ontario greenhouses turn a backup system into an asset.

4,000

Number of old, energy-sapping refrigerators, freezers and room air conditioners collected from our customers.

880,000

Number of our customers who participated in one of our conservation and demand management programs.

Ontario's greenhouses not only contribute about $2 billion a year to the province's economy, the network of generators managed by the CF Group and connected to Hydro One's grid now contributes about 4 MW of electricity, enough to power 1,300 homes.

Finding new ways for customers to use electricity wisely is the goal of Hydro One's Conservation and Demand Management group. In 2006, Hydro One not only helped enterprises like greenhouses and wind farms connect to the grid, we worked with our approximately 1.3 million residential customers to reduce peak demand.

Programs like SmartStat, the PowerCost Monitor and Appliance Retirement made a concrete difference to the amount of electricity Hydro One customers used. Our team removed more than 4,000 energy-hogging refrigerators from the grid. Our Power$aver tour, in conjunction with Home Depot, travelled the province and provided customers with vital information on ways to reduce electricity usage and offered advice on energy efficient products.

By working together and encouraging innovation, Hydro One and Ontario energy users and generators can meet future challenges.

Hydro One helped CF Group Greenhouses connect about 4 MW of electricity to the grid, enough to power about 1,300 homes in times of short supply.

Hydro One's 2006

accomplishments

In 2006, Hydro One completed digging a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative project will carry an array of electricity transmission lines to tie the east and west halves of the city together, with minimal disruption to traffic or residents. Expanding the links between east and west by running new transmission lines through the $45 million investment will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

The project is scheduled for completion late next year with the new 230-kV circuit expected to be operational by early 2008.

Hydro One has signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems.

The $124 million investment for Hydro One will add an important new connection between the two grids. The first phase of the project – the new connection with Ontario – will come into service in early 2009, and will have a capacity of 900 MW. The second phase – the addition of a reinforcement line – will be brought into service in the spring of 2010, and will increase the connection's capacity to 1,250 MW.

Highly Rated

Dominion Bond Rating Service raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. In addition, our short-term debt rating was upgraded to R-1 (middle) from R-1 (low).

Construction crews rebuilt the interconnection in the Sarnia area with the transmission operator in Michigan. This connection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of our existing high-voltage transmission system.

Hydro One is reinforcing the high-voltage transmission system in the Niagara region which will help significantly in meeting electricity needs in Southern Ontario during high-demand periods.

These upgrades will increase power import capacity from New York State up to 800 megawatts – enough power to meet the needs of about 260,000 homes – and accommodate additional power supplied by Ontario Power Generation's Sir Adam Beck stations after completion of a third tunnel at Niagara Falls.

Close to

100

MILLION kWh,

enough electricity to power 8,200 homes for one year, were saved by Hydro One's customers through our conservation and demand management programs.

In August, the Kleinburg Training Centre opened its doors to teach Ontario's future electricity workers.

The need for the facility was clear with the number of apprentices needing training doubling from 176 in 2003 to close to 400 in 2006.

This facility allows us to give the next generation of line maintainers, meter readers, distribution technicians, protection and control trainees hands-on experience in a safe environment.

The centre not only provides vital training to Hydro One apprentices, it's a Ministry of Training, Colleges and Universities certified facility. Apprentices from utilities across the province come here to put spurs on for the first time and take those tentative first steps up a wooden pole.

Customers told us the old system for checking outages on our website was cumbersome, so we improved it. Our redesigned online Power Outage Notification system improves communications between Hydro One and the public and provides real-time information to the media during major storms or other outage situations. The new system paints a very accurate picture of the status of our electricity transmission and distribution system.

$807,728

was raised by Hydro One employees for charities of their choice in 2006.

Hydro One Senior Management

Laura Formusa
President and Chief Executive Officer
(Acting)
Hydro One Inc.

Joe Agostino
General Counsel
(Acting)

Myles D'Arcey
Senior Vice-president,
Customer Operations

Steve Dorey
Vice-president,
External Relations

John Fraser
Vice-president, Internal Audit
and Chief Risk Officer

Tom Goldie
Senior Vice-president,
Corporate Services

Peter Gregg
Vice-president,
Corporate and Regulatory Affairs
and Executive Office

Rick Kellestine
Vice-president,
Culture

Nairn McQueen
Vice-president,
Engineering and
Construction Services

Geoff Ogram
Vice-president,
Asset Management

Wayne Smith
Vice-president,
Grid Operations

Beth Summers
Chief Financial Officer

Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2006 and 2005.

Overview

We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2006, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

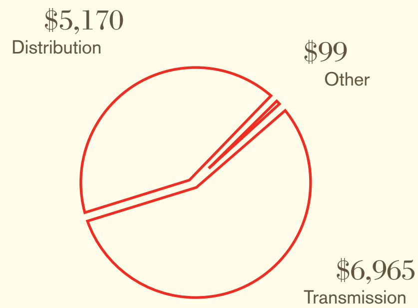
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2006, we earned total transmission revenues of $1,245 million primarily by transmitting approximately 151 TWh of electricity, directly or indirectly, to more than 4 million customers. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our transmission business is our largest segment, representing approximately 60% of our total assets.

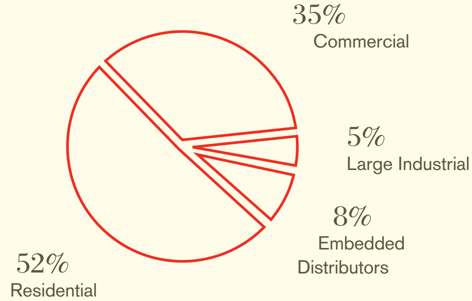
Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 48 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, over half of our distribution revenues are earned from our residential customers.

Total Assets
December 31, 2006
(Cdn $ millions)



2006 Distribution Revenues



Other

Our other business segment contributed revenues of $27 million in 2006 and has assets of about $99 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2006, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value, while striving to attract, develop and retain productive employees.

We seek to achieve these goals by continuing to implement the following strategies:

— *Safety:* Create and maintain an injury-free workplace with a concentrated focus on elimination of serious injury and "near misses" in high potential harm categories of work.

— *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.

— *Reliability:* Enhance the reliability of our transmission and distribution systems. In transmission, we have assumed a proactive leadership role in developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.

— *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.

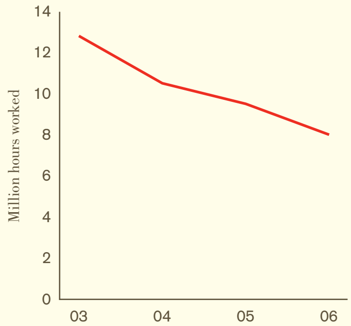
— *Employees:* Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

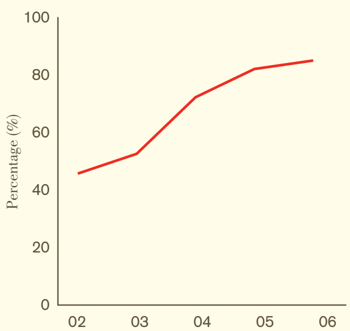
We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We substantially met or exceeded our challenging 2006 objectives, improving in a number of areas over 2005, and are moving towards achieving our strategic goals.

The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to achieve a record of no serious injuries and no serious near misses. Accordingly, we measure our high Maximum Reasonable Potential for Harm (MRPH) incidents rate to identify possible problems or situations that may increase the risk of injury. As shown in the accompanying chart, we had eight high MRPH incidents per million hours worked in 2006, which is 16% lower than 2005, 24% lower than 2004, and 38% lower than 2003.

High MRPHs



Large Transmission Customer Satisfaction



We also maintain our focus on serious incidents in high risk areas including electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. The number of serious incidents declined from about nine incidents per million hours worked in 2003, to approximately five in 2006. Going forward, we will continue to stress the importance of safety through a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments, development of a learning management system and further use of decision analysis tools to reduce human error and its consequences.

Customer satisfaction is also vital to our success. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 83% to 86% satisfied as compared to 2005. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our Residential and Small Business Customers and survey results show an increase in the level of satisfaction to 83% satisfied from 81% last year. While our 2006 Generator satisfaction level of 74% was acceptable, it was slightly below our annual target, and addressing the concerns identified will be an area of focus in 2007. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

Weather patterns and generation constraints require exemplary performance from both our transmission and our distribution systems. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2006, we met our annual reliability targets and achieved some improvements over 2005. We did so while managing the impacts of a number of devastating storms throughout the year, including the back-to-back storms experienced over the summer. We enhanced our storm response and communication, including improving processes, improving our website and providing "real time" information through emails and faxes. Subsequent to year end, the Edison Electric Institute (EEI) honoured us with an emergency recovery award for our outstanding efforts to restore electricity service during these storms. This is the first time this prestigious award has been won by a utility outside of the U.S.

Meeting our shareholder requirements is an integral part of our business focus. Strong financial performance was again characterized by our 2006 results and we maintained or improved credit ratings on both our short-term and long-term debt. On June 23, 2006, Dominion Bond Rating Service Inc. raised our short-term debt rating to R-1 (middle) and our long-term debt rating to A (high), as a result of key factors including their expectation that our financial profile will remain strong over the medium to long term.

Regulation

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). The OEB sets prices at least every 12 months, or more frequently, and may upon review, reset prices over the next 12 months to better reflect the cost of supply. The OEB currently plans to review the need to reset prices every six months. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and to assist with the stability of rates for RPP customers, among others. As part of its mandate to ensure the adequate long-term supply of electricity, and consistent with the Province's direction regarding supply mix, the OPA is in the process of developing the Integrated Power System Plan (IPSP), which must be submitted for review and approval to the OEB which will conduct public hearings and consultation. The OPA currently expects to submit the IPSP to the OEB in March 2007. As part of the IPSP process, the OPA has issued a number of discussion papers for comment by stakeholders. Of the papers issued to date, two are most important to the transmission business and influence our capital expenditures; "Discussion Paper 5 – Transmission" and "Discussion Paper 7: Integrating the Elements – A Preliminary Plan" (See "Future Capital Expenditures" on page 29).

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination will further initiatives undertaken by individual local distribution companies (LDCs), including our distribution business, as a result of distribution rate increases approved in 2005. Some of the funds associated with this increase were required to be used on CDM programs. Our programs amounted to approximately $43 million over the period 2005 to 2007, consistent with this direction. The overall goal of the CDM programs is to reduce provincial demand by 6,300 MW by 2025. The OPA issued "Discussion Paper 3 – Conservation & Demand Management" and is expected to submit a CDM plan as part of the IPSP.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely and providing customers with access to information about their consumption. A new entity will oversee the communications systems and technologies, collect and manage data, and facilitate meter procurement. LDCs, including our distribution businesses, will own, install, operate and maintain their own meters. We are currently deploying smart meters under our program (See "Future Capital Expenditures" on page 29).

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. In 2000, the OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks), seeking approval of a revenue requirement of $1,263 million for 2007 and $1,298 million for 2008, subject to minor updates in the normal course. This application is based on achieving a 10.5% return on equity and an increase in the common equity component of the capital structure from 36% to 40%. The proposed rate increases are 4.3% in 2007 and 2.7% in 2008, with the impact on an average customer's total bill estimated to be less than 0.5% in both years. Consistent with the OPA discussion papers, the application includes funding to enable new generation and ensure the adequacy of area supply, as well as the continued reliability of aging transmission assets. We believe the proposed regulated return, in conjunction with capital structure, supports the financial metrics underlying an A credit rating category, facilitating access to capital markets at reasonable rates.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue decreased by approximately $13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates were initially approved by the OEB in 2000 to provide for cost recovery and a return on deemed common equity targeted to be 9.88%. Related distribution rate increases were phased in over a number of years, with the final installment approved by the OEB in March 2005. In August 2005, we filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. On April 12, 2006, the OEB announced its decisions regarding this application and that of our distribution business conducted by Hydro One Brampton Networks Inc. (Hydro One Brampton). On the basis of the written and oral evidence submitted, the OEB approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

While current distribution rates are based on a cost of service rate regulation model, the OEB is in the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007–2010. Consistent with OEB guidelines, we plan to apply for distribution rate adjustments in February 2007, with minimal impact anticipated on the total customer bill. This application is based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management.

On March 21, 2006, the OEB approved a monthly rate of 30 cents per residential customer, effective May 1, 2006, as initial funding for the required investment in smart meters. The distribution rate application, to be filed with the OEB in February 2007, will include a request to increase this level of smart meter funding. Expenditures in excess of recoveries are currently being recorded as a regulatory asset, with disposition to be established at a later date.

Results of Operations

Revenues

Year ended December 31

(Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	1,245	1,310	(65)	(5)
Distribution	3,273	3,085	188	6
Other	27	21	6	29
	4,545	4,416	129	3
Average annual Ontario 60-minute peak demand *(MW)* [1]	22,650	23,074	(424)	(2)
Distribution – units distributed to customers *(TWh)* [1]	29.0	29.7	(0.7)	(2)

[1] System-related statistics include preliminary figures for December.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Transmission revenues decreased by $65 million, or 5% in 2006, compared to last year, reflecting two recent OEB decisions. On February 21, 2006, the OEB applied an earnings sharing mechanism to any transmission earnings in excess of our approved rate of return of 9.88% for the period January 1, 2006 until new rates are set. Consequently, 50% of excess earnings recovered from customers are deferred as a regulatory liability. This decision had the effect of reducing transmission revenues by $33 million for the year. On December 8, 2005, the OEB adjusted revenue allocation factors for all of the Province's electricity transmitters, reducing 2006 transmission revenues by $13 million.

In addition, 2006 monthly peak demands were generally lower than last year. While there were a few exceptions, notably the all-time record peak demand of 27,005 MW set on August 1 and the May record peak demand of 24,857 MW, our average annual Ontario 60-minute peak demand was 424 MW lower and the overall related load was 5,083 MW lower than last year, resulting in lower revenues of $26 million. The impact of these reductions was partially offset by a marginal increase in ancillary revenues related to revenues earned from the secondary use of our land rights-of-way.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by our distribution rates, the amount of electricity we distribute and the cost of purchased power. Distribution revenues also include minor ancillary services revenues, such as rental fees charged to telecommunications and cable television companies for the use of our poles, and miscellaneous charges such as those made for late payments.

Distribution revenues increased by $188 million, or 6%, in 2006 compared to last year, primarily as a result of two OEB-approved distribution tariff rate increases that became effective April 1, 2005 and May 1, 2006. The April 1, 2005 increase was originally scheduled to be effective March 1, 2003, and was subsequently suspended for all LDCs by the *Electricity Pricing Conservation and Supply Act, 2002*. On April 12, 2006, after reviewing our evidence, the OEB approved increases in distribution tariff rates for our distribution businesses conducted by Hydro One Networks and Hydro One Brampton, effective on May 1, 2006. We also received OEB approval for low-voltage rates for services provided to LDCs that are embedded within our service territory. These tariff rate increases support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, and resulted in higher distribution revenues of $105 million compared to last year.

Distribution revenues also include the recovery of increased purchased power costs of $90 million, as described below under "Purchased Power." The impact of the increases in tariff rates and purchased power costs was partially offset by lower distribution tariff revenues of $5 million associated with lower demand, as well as marginally lower ancillary revenues.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory. These costs consist of the wholesale commodity cost of electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. From April 1, 2004 to March 31, 2005, for certain low-volume and designated customers, the commodity price of electricity was based on an interim two-tiered pricing structure. This structure was subsequently replaced by the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP continue to pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the interim pricing plan and RPP affecting the two-year period 2005 and 2006 is provided below.

Summary of Interim Pricing Plan & RPP

		Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Price Plan	Effective Date	Residential	Non-Residential	First Tier	Second Tier
Interim	April 1, 2004	750	750	4.7	5.5
RPP	April 1, 2005	750	750	5.0	5.8
RPP	November 1, 2005	1,000	750	5.0	5.8
RPP	May 1, 2006	600	750	5.8	6.7
RPP	November 1, 2006	1,000	750	5.5	6.4

Purchased power costs increased in 2006 by $90 million, or 4%, to $2,221 million compared to last year. Our increased purchased power costs were primarily due to higher costs of $189 million associated with the OEB's RPP for residential and other eligible customers, combined with the 2005 impact of providing the *Ontario Price Credit* to RPP customers in accordance with a regulation issued in October 2005. This $140 million credit was provided to RPP customers in 2005 to recognize a lower cost of power than the fixed commodity price for the period April 1, 2004 to March 31, 2005. These increases were partially offset by lower wholesale commodity prices of $137 million for customers who are not eligible for the RPP, and lower wholesale market service charges levied by the IESO of $55 million. The remaining $47 million reduction was due to a lower demand for electricity.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	390	353	37	10
Distribution	460	413	47	11
Other	30	26	4	15
	880	792	88	11

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $37 million, or 10%, in 2006 compared to last year. Within our work programs, we continued to make the investments necessary to ensure the safe and reliable operation of our installed transmission system, with particular focus on the assets that are critical to generation and to the unrestricted supply of electricity to our customers. We experienced increased work program requirements of approximately $32 million this year, primarily related to increased station maintenance expenditures, including our focus on our 750 MVA autotransformers, higher employee benefit costs attributable to a lower discount rate for actuarially determined benefit costs, economic increases in materials and fuel costs and the impact of a labour disruption in 2005. Other support costs increased marginally by $5 million in 2006 compared to the previous year. Higher information technology requirements this year, combined with the impact of last year's recoveries associated with insurance settlements and bad debt recoveries, were substantially offset by this year's cost reduction associated with a negotiated property tax settlement.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $47 million, or 11%, compared to last year. We experienced increased work program requirements of approximately $50 million, primarily within our lines and customer care work programs. These increases reflect our recovery efforts following a series of destructive storms, particularly in the third quarter. In 2006, we experienced 10 significant storm events, compared to 4 in 2005. Consequently, our storm-related repair and maintenance expenditures for our distribution business increased by approximately $13 million to $21 million. In addition, our annual work program expenditures were impacted by higher fuel costs, the same economic increases that we experienced within our transmission business, and the effects of last year's labour disruption. Other costs incurred to support our distribution work programs declined by about $3 million, primarily as a result of our reassignment of resources to support our larger capital program this year, partially offset by the impact of higher information technology requirements.

Depreciation and Amortization

Depreciation and amortization expense increased by $28 million, or 6%, to $515 million this year. Depreciation expense was higher by $10 million relative to 2005, primarily as a result of the placement of new assets in service, consistent with our ongoing capital work program. Year-over-year, amortization of regulatory and other assets increased by $18 million. This increase was attributable to increased amortization of our regulatory assets as a result of the OEB's April 12, 2006 decision to approve recovery of certain regulatory assets.

Financing Charges

Financing charges declined by $30 million, or 9%, to $295 million compared to last year. Approximately $25 million of this decrease was due to a lower average effective interest rate on our outstanding long-term debt. In addition, we capitalized approximately $5 million more interest this year, primarily as a result of a higher level of capital expenditures.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes declined by $19 million, or 10%, to $179 million in 2006 compared to 2005. Approximately $17 million of this reduction was due to this year's lower taxable income. The tax benefit of approximately $30 million that was recognized in the first quarter of 2006 pertaining to the recovery of prior years' corporate income taxes, was partially offset by the impact of last year's second quarter tax benefit in the amount of $21 million, which pertained to prior period tax losses of one of our subsidiaries. Payments in lieu of corporate income taxes were also reduced by tax changes enacted in the second quarter of 2006 relating to the elimination of the federal large corporations tax and higher capital cost allowance rates. These impacts were partially offset by taxes payable on transmission amounts received but not recognized for accounting purposes, primarily due to the OEB's earnings sharing mechanism.

Net Income

Net income of $455 million was lower by $28 million, or 6%, compared to 2005 results. Our net income for the year reflects higher expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, combined with lower transmission tariff revenues resulting from lower demand and the effects of the OEB's earnings sharing mechanism. The impact of these factors was partially offset by higher distribution tariff revenues associated with OEB-approved tariff rate increases and a marginal reduction in our effective tax rate. This tax rate reduction primarily resulted from the relative sizes of the tax benefits recognized in the first quarter of 2006 and in the second quarter of 2005.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2005 through December 31, 2006. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)				**2006**				2005
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues [1,2]	**1,142**	**1,165**	**1,078**	**1,160**	1,025	1,179	1,018	1,194
Net income [1,2]	**101**	**103**	**99**	**152**	104	133	115	131
Net income to common shareholder [1,2]	**96**	**99**	**94**	**148**	99	129	110	127

1 The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

2 Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31

(Canadian dollars in millions)	2006	2005
Operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Investing activities		
Capital expenditures	(823)	(691)
Other financing and investing activities	11	1
Net change in cash and cash equivalents	(20)	–

Operating Activities

Net cash from operating activities decreased by $273 million to $896 million, compared to 2005 results. This reduction primarily reflects the impact on our working capital requirements of providing RPP customers with the $140 million *Ontario Price Credit* early in 2006, funding for which was received by us from the IESO in late 2005. Our working capital requirements were also impacted by higher electricity prices charged to RPP customers in 2006, changes in the timing of tax payments and changes in trade accounts payable balances related to our work programs.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks which matures in August 2007 and which has a two-year extension option. As at December 31, 2006, we had $60 million in short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2006, we had $5,270 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $1,725 million is remaining and is currently available until July 2007.

During 2006, Dominion Bond Rating Service Inc. raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. Our short-term debt rating was upgraded to R-1 (middle) from R-1 (low). Our credit ratings are:

Rating Agency	Rating: Short-term Debt	Rating: Long-term Debt
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement that supports our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2006, we issued $775 million in long-term debt under our medium-term note program and we repaid $589 million in maturing long-term debt. In comparison, during 2005 we issued $500 million in debt under our medium-term note program and we repaid $648 million in maturing long-term debt. In 2006, we increased our short-term notes by $60 million compared to a reduction of $40 million in 2005.

In 2006, we paid dividends to the Province in the amount of $350 million, consisting of $332 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $273 million and preferred dividends of $18 million. In 2006, cash dividends per common share were $3,320 compared to $2,730 per common share in 2005. Cash dividends per preferred share were $1.375 in both 2006 and 2005.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations, the level of net income and timing. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

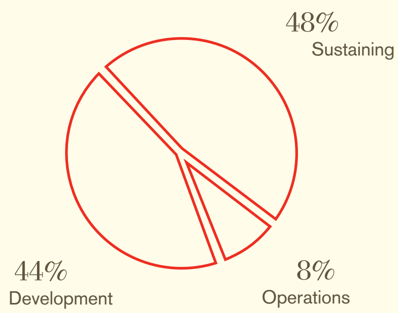
Year ended December 31 (Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	**402**	349	53	15
Distribution	**417**	338	79	23
Other	**4**	4	–	–
	823	691	132	19

Transmission

Transmission capital expenditures increased by $53 million in 2006 to $402 million, compared to 2005. Expenditures to expand and reinforce the transmission system were $179 million, $54 million higher than last year. These increased development investments primarily reflect higher required generation and load customer connection expenditures in this year. Our generation-related expenditures included a major reconfiguration of our Lambton Transformer Station, to enable the connection of new gas-fired generation. Increased load customer connection work included construction of a new transformer station to accommodate growth in Simcoe Region and work on transformer station improvements in Durham Region. Our development expenditures also included two critical projects to improve the flow of electricity in recognition of growing needs: the Niagara Reinforcement Project, which will reinforce the transmission system in the Niagara region and provide access to new sources of generation; and our Downtown Toronto Cable Project, which involves the construction of two underground cable circuits to reinforce our electricity transmission facilities. Our Niagara Reinforcement Project is essentially complete. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area and discussions continue between the affected aboriginal peoples and the various government entities involved. Once we regain access and perform a site condition assessment, we expect project completion within six weeks. In 2005, we substantially completed construction of the Parkway Transformer Station and refurbishment of the Cooksville Transformer Station. Both projects were carried out to accommodate the closure of the Lakeview Generating Station.

Our expenditures to sustain the existing transmission system were $192 million, representing a marginal decrease of $1 million compared to last year. Additional sustainment expenditures were made to replace storm-damaged equipment and to purchase new transformers. The impact of these requirements, together with the impact of last year's labour disruption, were substantially offset by reduced engineering and construction expenditures related to the refurbishment and replacement of end-of-life lines, stations and telecommunications assets. Other transmission capital expenditures were $31 million, unchanged from last year.

2006 Transmission Capital Expenditures

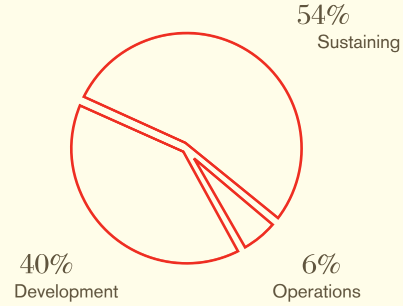


Distribution

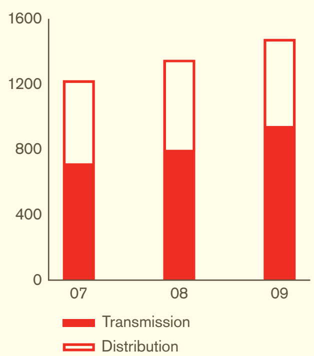
Distribution capital expenditures increased by $79 million to $417 million in 2006, compared to the prior year. Expenditures to sustain our low-voltage distribution system were $225 million, an increase of $63 million over 2005. This increase was primarily a result of higher storm-related expenditures to replace damaged assets. Year-over-year capital expenditures for storm restoration were $62 million, an increase of $36 million. As a result of the significant storm activity this year, we replaced more than 1,600 distribution poles and more than 200 kilometres of line. Increased sustainment expenditures also reflect higher planned replacements of end-of-life assets, unplanned asset replacements and line relocations, as well as the impact of last year's labour disruption.

Capital expenditures to expand and reinforce our distribution network were $167 million, an increase of $20 million compared to last year. This increase primarily reflects our deployment of smart meters during the year. Our other distribution capital expenditures decreased by $4 million to $25 million.

2006 Distribution Capital Expenditures



Future Capital Expenditures
(Cdn $ millions)



Future Capital Expenditures

Our capital expenditures in 2007 are budgeted at about $1.25 billion, an increase of over $400 million from 2006 levels. The 2007 capital budgets for our transmission and distribution businesses are about $700 million and $500 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to be approximately $1.35 billion in 2008 and $1.5 billion in 2009, primarily reflecting increasing investments in necessary transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with the OPA's discussion papers and the needs of our aging transmission system under continued challenging conditions of tight generation supply. These investments will facilitate an adequate and reliable supply of electricity in the public interest. The investment levels also reflect the mass deployment of smart meters within our distribution businesses beginning in 2007. The replacement of critical information technology systems is also contemplated. Capital expenditures of our other business segment are budgeted at about $20 million in 2007, largely due to the implementation of a dedicated optical network to provide secure, high capacity connectivity across numerous health care locations in Ontario.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2007 to 2009, amounting to almost $2.4 billion. Our investment plan will address new development and supply enhancement initiatives, including system expansion, generation requirements and load connections. The transmission program also continues the focus on "mission critical" assets, which are those assets critical to generation facilities and the unrestricted transmission of energy to our customers.

The development component of our investment plan for transmission includes enhancements to the transmission system in the Bruce Peninsula to accommodate new wind generation and redeveloped nuclear generation; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Midtown Toronto; and a new interconnection between Ontario and Quebec. Initiatives taken by the Province and the OPA have led to many new generation developments and we are undertaking investments to connect many of these to the transmission system. Major connections include large new gas generators in Sarnia, the west GTA and downtown Toronto, and several large new wind farms. Several projects have need dates that cannot be met if approvals are delayed beyond the release of the IPSP. As such, we have initiated the processes required to file Leave-to-Construct applications with the OEB and to receive other approvals as required.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Investments in mission critical assets ensure a reliable supply of energy throughout the province. Through targeted replacement programs for components such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes, continues to be essential. Examples of projects initiated to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston and Red Lake. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems will lead to improved reliability.

The timing of many development projects is uncertain as they are dependent upon the final IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Consistent with our approved 2006 distribution rate applications, capital expenditures for the period 2007 to 2009 are budgeted at approximately $1.7 billion. This amount includes core development and sustainment work as well as our smart meter program. Our core work will focus on new load connections, trouble calls and storm damage, wood pole replacement, and system capability reinforcement. Given initiatives to encourage renewable energy technologies, we also anticipate increased connection of new generators which could trigger the need for larger system modifications.

Our distribution investment plan includes the mass rollout of the smart meter program. Over the period 2007 to 2010, we anticipate installing over 1 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program and install 240,000 meters. At the Province's request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2006 (Canadian dollars in millions)	Total	2007	2008/2009	2010/2011	After 2011
Contractual obligations (due by year):					
Short-term note payable	60	60	–	–	–
Long-term debt – principal repayments	5,270	395	900	650	3,325
Long-term debt – interest payments	4,769	291	524	448	3,506
Inergi LP (Inergi) outsourcing agreement[1]	496	110	192	178	16
Operating lease commitments	16	5	9	1	1
Total contractual obligations	10,611	861	1,625	1,277	6,848
Other commercial commitments (by year of expiry):					
Bank line[2]	750	750	–	–	–
Letters of credit[3]	118	118	–	–	–
Guarantees[3]	275	275	–	–	–
Pension[4]	8	8	–	–	–
Total other commercial commitments	1,151	1,151	–	–	–

[1] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[2] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2007, with a two-year extension option.

[3] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $22 million and parental guarantees of $275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one month in arrears. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to $100 million.

The long-term debt amounts in the above table are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or within our capital expenditures. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our payments in lieu of corporate income taxes, which are paid or payable to the OEFC.

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices and our Chief Financial Officer for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province of Ontario

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence major business and corporate decisions. Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve potential conflicts with the Province on terms satisfactory to us.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rates of return.

On September 12, 2006, Hydro One Networks filed, with the OEB, its application and evidence in support of its 2007 and 2008 transmission revenue requirements based on a capital structure with a higher equity component and a higher return on equity. Our operation, maintenance and administration expense levels have increased over time and our transmission business rate base has increased, reflecting prudent expenditures, since transmission rates were initially established. However, there is the risk that these increases may be disallowed by the OEB. Any disallowed capital expenditures would be charged to the results of operations in the period that the OEB renders its decision. Insufficient funding for our transmission business could adversely impact our financial results and the operating performance of the transmission system.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2007, which could significantly reduce our revenues, particularly transmission. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transmission facilities by constructing their own assets under certain conditions.

There is also a risk we could be required to invest in large-scale transmission infrastructure projects, to incur unexpected capital expenditures to maintain or improve our assets, and to connect new third-party generation assets. The Province has passed regulations authorizing us to procure smart meters but we are only currently authorized to recover 30 cents of the associated costs in rates. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential charges to our results of operations.

Asset Condition

We continually maintain our assets to provide reliable service and to accommodate customer needs. However, our installed asset base is aging to the point where the assets require increased maintenance, major refurbishment or replacement. Executing these activities is also becoming more challenging as the opportunities to remove equipment from service to accommodate work are becoming increasingly limited. Consequently, we may not be able to complete the necessary repairs and replacements on a cost-effective or timely basis, which could affect transmission reliability and our ability to deliver sufficient electricity.

Risk Associated with Transmission Projects

Significant investments are needed to increase transmission capacity and enable the delivery of reliable electricity from existing and new generation sources to Ontario consumers. These investments are, in most cases, subject to OEB approvals, which can include expropriation, and where required, environmental approvals and consultation and possibly accommodation with First Nations. The ability to make such investments may also be impacted by public opposition. If we are unable to make these necessary investments, the reliability of our transmission system and our ability to deliver sufficient electricity could be materially adversely affected.

Work Force Demographic Risk

Approximately 25% of our employees will be eligible for retirement by 2008. We expect the skilled labour market for our industry to remain highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union or the Society of Energy Professionals. Existing collective agreements with the Power Workers' Union and the Society of Energy Professionals expire on March 31, 2008. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). It is expected that these draft regulations will be finalized later in 2007. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our balance sheet. If required, most of these additional expenditures would be incurred in the 2013 to 2025 period. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to withstand such occurrences, our facilities may not do so in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2007 and 2010. We also plan to incur total capital expenditures of approximately $1.25 billion in 2007 and $1.35 billion in 2008. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and our future capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The next valuation will be prepared as at December 31, 2006 and must be filed on or before September 30, 2007. The required level of contributions effective January 1, 2007 will depend on future investment returns, changes in benefits, and changes in actuarial assumptions. Based on current factors, we estimate annual pension contributions for 2007 and beyond to be up to $100 million per annum. Pension costs are subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $850,000 per year that we are currently paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have an adverse effect on our results of operations if we are unable to recover them in future rate orders.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors in conjunction with the operation our systems may increase safety or environmental risks.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, capture data and produce timely and accurate information used in our business. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing our operating costs, in 2002 we entered into an outsourcing services agreement with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have an adverse effect on our results of operations.

Market and Credit Risk

Market risk refers primarily to risk of loss related to changes in commodity prices, foreign exchange and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2007 and 2008 would have an impact on net income of approximately $2 million and $4 million, respectively. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of $40 million and an insignificant fair value.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2006 amounted to $311 million and principally relate to the regulatory asset recovery accounts (RARAs), employee future benefits other than pension, environmental costs, and expenditures associated with the smart meter program. We have also recorded regulatory liabilities amounting to $473 million as at December 31, 2006. These amounts pertain primarily to pension, export and wheeling fees, and the transmission earnings sharing mechanism. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARAs, or if future OEB direction is judged to be probable. Most of our regulatory assets have been reviewed by the OEB and confirmed as recoverable.

To date, our smart meter expenditures and recoveries have been recorded in regulatory asset accounts consistent with OEB guidance. The timing and amount of inclusion of these amounts in our Statement of Operations is currently uncertain and will depend on future OEB decisions as well as other factors.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related assets for the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our demerger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing the work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of 2% has been used to express current cost estimates as future expenditures. These expenditure amounts have been discounted using a factor of 6.25%. Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or whenever significant changes in regulation occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets exceeded this long-term assumption in 2006.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2006 increased by 0.25% from those at December 31, 2005 in conjunction with increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $13 million per year.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2006 and we determined that the carrying value of our goodwill has not been impaired.

Emerging Accounting Pronouncements

Transition to International Financial Reporting Standards (IFRS)

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over a five-year transitional period. The AcSB published an updated detailed implementation plan for achieving convergence in June 2006. The plan calls for the first year of reporting under IFRS to be 2011. At that point, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we began our transition preparations in 2006.

Accounting for Rate-Regulated Operations

Following the approval of its new strategic plan to adopt IFRS, the AcSB revisited the scope of its project on rate-regulated accounting in recognition of the fact that that IFRS does not currently provide any special accounting treatment for rate-regulated enterprises. As a result, the AcSB is expected to issue an exposure draft in early 2007 to propose removal of all specific references to rate-regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). It is expected that the AcSB will allow qualifying enterprises to apply the relevant U.S. accounting standard, Statement of Financial Accounting Standard 71 *Accounting for the Effects of Certain Types of Rate Regulation* (SFAS 71). Enterprises subject to rate regulation will be qualified to use SFAS 71 as long as they meet the specific criteria found in that accounting standard and as long as they apply it in the manner the U.S. standard setter intended. We believe our company meets these criteria. The future application of SFAS 71 will have an impact on our financial statements. Accrual accounting practices will be followed for payments in lieu of corporate taxes, which are currently accounted for on a cash basis as a result of specific OEB direction. The difference between the accrual and cash basis will be reflected through the recognition of additional regulatory assets and, consequently, the impact on our results of operations is expected to be minimal.

Financial Instruments

In 2005, the CICA issued new accounting standards comprising Handbook Section 3855, *Financial Instruments Recognition and Measurement;* Section 3865, *Hedges and* Section 1530, *Comprehensive Income*, all of which become effective for us on January 1, 2007.

The standards require that all financial assets, including derivatives, be carried at fair value on the balance sheet, with the exception of loans, receivables and investments classified as held to maturity, which will be measured at amortized cost. Similarly, all derivative financial liabilities will be measured at fair value on the balance sheet. Other financial liabilities will be measured at amortized cost.

The standards also revise the existing accounting requirements for hedges and establish guidance for reporting comprehensive income, which includes net income and other comprehensive income. Any hedge ineffectiveness will be recognized immediately in the results of operations. Any changes in the fair value of cash flow hedging instruments, to the extent effective, will be recorded in other comprehensive income until the asset or liability being hedged affects the Statement of Operations, at which time the related change in fair value of the derivative will also be recorded in the Statement of Operations. Unrealized gains and losses on changes in the fair value of cash flow hedging instruments will be recorded as other comprehensive income until recognized in the Statement of Operations. This would include any remaining balance of deferred gain or loss on a cash flow hedge that was discontinued prior to the transition date.

Given the nature of our financial instruments and borrowing programs, we do not believe that the transitional impact of the new accounting standards will have a material financial impact on our company.

Accounting for Pension and Other Post-Retirement Costs

In October 2006, the AcSB commenced a project that is expected to result in a requirement to include the funded status (the difference between the plan assets and obligations) of an entity's post-retirement benefit plans on the balance sheet and to recognize changes in the funded status in comprehensive income in the year in which the changes occur. Current Canadian GAAP only requires disclosure of the funded status in the notes to the financial statements. The project will affect disclosures relating to our pension plan, supplementary pension plan, other post-employment and other post-retirement benefits. In addition, the proposals are expected to have a significant adverse impact on our financial ratios. The proposals, however, are not expected to impact our credit rating. The AcSB expects to publish the exposure draft for public comment in the first quarter of 2007 and it is expected to be effective for our company on December 31, 2007. This timing is expected to allow sufficient time to assess the effects on financial metrics referred to in existing contractual arrangements, including debt covenants.

Disclosure Controls and Internal Controls Over Financial Reporting

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. During 2005, we designed and evaluated the effectiveness of our disclosure control procedures. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that these disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

During 2006 we completed our documentation, evaluation and remediation of internal controls over financial reporting. Our documentation includes flowcharts of key processes, risk matrices, and overviews of test results and remediation activities. The majority of findings related to the evidencing of controls and all remediation was completed during the period. Our focus for 2007 will be the ongoing sustainment of our control environment including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2006, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the presentation of financial statements for external purposes in accordance with GAAP. Our Certifying Officers have evaluated the effectiveness of our disclosure controls and procedures and have found them to be effective.

Outlook

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our top strategic priorities relating to safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our long-term customer satisfaction and safety targets, while we maintain our strong financial profile and reliability performance. In addition, the North American Electric Reliability Council gave our transmission operating facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The EEI has also honoured us with an emergency recovery award, recognizing the outstanding efforts of our staff in restoring electricity service this summer after the significant damage caused by successive storms.

With the approval and implementation of the 2006 distribution rate increase, we are reasonably well positioned to address current distribution work program requirements and to earn the regulated rate of return. This will allow us to further the forestry program and continue initiatives to improve reliability and customer service. We continue to face challenges with regard to funding for our smart meter program. We expect to address some of the shortfall in our February 2007 application and anticipate full funding to be achieved over time.

We remain committed to a prudent and measured approach to distribution rationalization. The Province plans to lift the moratorium on the purchase and sale of electricity distribution assets by Hydro One, with the understanding that any future asset purchases or dispositions help further overall provincial policy interests in the sector. We plan to respond to opportunities, on a voluntary and commercial basis, where they are consistent with strategy. The investment plan does not include any funding for LDC acquisitions or divestitures. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of mission critical assets to ensure the system's continued reliability. Our transmission investment plan supports the achievement of supply mix goals, facilitates the development and use of renewable energy resources, promotes system efficiency and congestion reduction, and facilitates the integration of new supply. The OPA has presented the needs and options for reinforcing and expanding Ontario's transmission system, and discussed the specific transmission initiatives forming the basis of the preliminary IPSP. Significant investments in transmission will be required over the 20-year planning horizon of the IPSP, which is expected to be submitted by the OPA to the OEB in March 2007. In September, we filed a transmission cost of service rate application with the OEB that includes the funding required for this necessary transmission infrastructure, which is vital to the Ontario economy. Given the issued schedule, a decision on our rate application is anticipated late in 2007. Our outlook is premised on the successful outcome of this application.

Our investment plan does not include spending for large-scale investments, such as the expansion of the east-west transmission grid. Funding for required infrastructure to accommodate Bruce Peninsula supply continues beyond the planning period to 2011. Completion of the Toronto third supply option, which is expected to cost in the order of $400 million, also extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and, as such, to maintain reliability.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

Forward-Looking Statements and Information

Our oral and written public communications, including this Management's Discussion and Analysis (MD&A), often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

— the content of the final IPSP, as approved by the OEB;

— delays or denials of the requisite approvals for planned future capital expenditures;

— regulatory decisions regarding our revenue requirements and tariff rates;

— significant changes to Environment Canada's draft PCB regulations issued on November 4, 2006; and

— future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in this Management's Discussion and Analysis. You should review the section entitled "Risk Management and Risk Factors" in detail.

This Management's Discussion and Analysis is dated as at February 14, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2007.

In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 45, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

L. Formusa

Laura Formusa
President and Chief Executive Officer (Acting)

Beth Summers
Chief Financial Officer

Auditors' Report

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2006 and December 31, 2005, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and December 31, 2005, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Toronto, Canada
February 14, 2007

Consolidated Statements of Operations

Year ended December 31 (Canadian dollars in millions)	2006	2005
Revenues		
Transmission *(Notes 8 and 14)*	1,245	1,310
Distribution *(Notes 3 and 14)*	3,273	3,085
Other	27	21
	4,545	4,416
Costs		
Purchased power *(Notes 3 and 14)*	2,221	2,131
Operation, maintenance and administration	880	792
Depreciation and amortization *(Note 4)*	515	487
	3,616	3,410
Income before financing charges and provision for payments in lieu of corporate income taxes	929	1,006
Financing charges *(Note 5)*	295	325
Income before provision for payments in lieu of corporate income taxes	634	681
Provision for payments in lieu of corporate income taxes *(Notes 6 and 14)*	179	198
Net income	455	483
Basic and fully diluted earnings per common share (Canadian dollars) *(Note 13)*	4,366	4,652

Consolidated Statements of Retained Earnings

Year ended December 31 (Canadian dollars in millions)	2006	2005
Retained earnings, January 1	1,079	887
Net income	455	483
Dividends *(Note 13)*	(350)	(291)
Retained earnings, December 31	1,184	1,079

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

December 31 (Canadian dollars in millions)	**2006**	2005
Assets		
Current assets:		
Accounts receivable		
(net of allowance for doubtful accounts – $19 million;		
2005 – $14 million) *(Note 14)*	**777**	628
Materials and supplies	**56**	56
Other	**13**	12
	846	696
Fixed assets *(Note 7)*:		
Fixed assets in service	**16,238**	15,553
Less: accumulated depreciation	**6,180**	5,818
	10,058	9,735
Construction in progress	**468**	375
	10,526	10,110
Other long-term assets:		
Deferred pension asset *(Note 11)*	**382**	449
Regulatory assets *(Note 8)*	**311**	400
Goodwill	**133**	133
Deferred debt costs	**24**	23
Other assets	**12**	10
	862	1,015
Total assets	**12,234**	11,821

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31 (Canadian dollars in millions)	**2006**	2005
Liabilities		
Current liabilities:		
Bank indebtedness	29	9
Accounts payable and accrued charges *(Note 14)*	661	700
Accrued interest	49	43
Short-term notes payable *(Note 9)*	60	–
Long-term debt payable within one year *(Note 9)*	395	589
	1,194	1,341
Long-term debt *(Note 9)*	4,872	4,466
Other long-term liabilities:		
Regulatory liabilities *(Note 8)*	473	495
Employee future benefits other than pension *(Note 11)*	803	716
Environmental liabilities *(Note 12)*	55	64
Long-term accounts payable and accrued charges	16	23
	1,347	1,298
Total liabilities	7,413	7,105
Contingencies and commitments *(Notes 10, 16 and 17)*		
Shareholder's equity *(Note 13)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,184	1,079
Total shareholder's equity	4,821	4,716
Total liabilities and shareholder's equity	12,234	11,821

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Rita Burak
Chair

Eileen Mercier
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 (Canadian dollars in millions)	2006	2005
Operating activities		
Net income	455	483
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	474	446
Transmission earnings sharing	33	–
Amortization of discount	27	58
Retail settlement variance accounts	7	12
Low-voltage services	(8)	(24)
	988	975
Changes in non-cash balances related to operations *(Note 15)*	(92)	194
Net cash from operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Termination of interest rate swap	–	(10)
Other	(4)	2
Net cash used in financing activities	(108)	(487)
Investing activities		
Capital expenditures	(823)	(691)
Other assets	15	9
Net cash used in investing activities	(808)	(682)
Net change in cash and cash equivalents	(20)	–
Cash and cash equivalents, January 1	(9)	(9)
Cash and cash equivalents, December 31 *(Note 15)*	(29)	(9)

See accompanying notes to Consolidated Financial Statements.

Note 1.
Description of the Business

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Note 2.
Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario) in 2007. The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review Hydro One's transmission rates and to approve revenue requirements for 2006, 2007 and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set. In September 2006, Hydro One Networks filed a transmission rate application. A decision on this application and the resulting revised transmission rates are anticipated in 2007.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. On the basis of the written and oral evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2006 amounted to $386 million (2005 – $377 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). 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 Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2006 – 6.39%; 2005 – 6.80%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated Service Lives (years)	
	Range	Average
Transmission	12–100	55
Distribution	15–75	41
Communication	7–40	19
Administration and service	5–50	39

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt.

Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations. Hedging gains and losses are amortized over the period of the related debt.

The Company does not engage in derivative trading or speculative activities.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Note 3.
Electricity Credits to Customers

Under a regulation issued in October 2005, Regulated Price Plan customers received a credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $140 million. The application of the credit did not result in any adjustment to net income.

Note 4.
Depreciation and Amortization

Year ended December 31

(Canadian dollars in millions)	2006	2005
Depreciation of fixed assets in service	379	369
Fixed asset removal costs	41	41
Amortization of regulatory and other assets	95	77
	515	487

Note 5.
Financing Charges

Year ended December 31

(Canadian dollars in millions)	2006	2005
Interest on short-term notes payable	2	1
Interest on long-term debt payable	296	297
Amortization of discount	27	58
Other	9	5
Less: Interest capitalized on construction in progress	(28)	(21)
Interest capitalized on regulatory assets	(7)	(10)
Interest earned on investments	(4)	(5)
	295	325

Note 6.
Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2006	2005
Income before provision for PILs	634	681
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	229	246
(Decrease) increase resulting from:		
Net temporary differences:		
Recovery of PILs related to prior years	(30)	(21)
Pension contribution in excess of pension expense	(16)	(25)
Employee future benefits other than pension expense in excess of cash payments	14	8
Transmission amounts received but not recognized for accounting purposes due to earnings sharing mechanism	12	–
Overhead capitalized for accounting but deducted for tax purposes	(11)	(10)
Interest capitalized for accounting purposes but deducted for tax purposes	(13)	(11)
Environmental expenditures	(6)	(5)
Capital cost allowance (in excess of) less than depreciation and amortization	(3)	1
Other	4	1
Net temporary differences	(49)	(62)
Permanent differences:		
Large corporations tax	–	13
Other	(1)	1
Net permanent differences	(1)	14
Provision for PILs	179	198
Effective income tax rate	28.23%	29.07%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized. In 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to utilize the subsidiary's accumulated tax losses and a future tax asset of approximately $21 million was recognized. As at December 31, 2006, approximately $2 million of the 2005 amount remains available for use in 2007.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax liabilities of $281 million (2005 – $265 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been higher by approximately $16 million, including the impact of a change in substantively enacted tax rates.

Note 7.
Fixed Assets

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	–	422
	16,238	6,180	468	10,526
2005				
Transmission	8,124	2,889	233	5,468
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	–	421
	15,553	5,818	375	10,110

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $28 million in 2006 (2005 – $21 million).

Note 8.
Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities (see Note 2):

December 31 (Canadian dollars in millions)	2006	2005
Regulatory assets:		
Regulatory asset recovery account I	58	88
Regulatory asset recovery account II	87	92
Employee future benefits other than pension	84	126
Environmental	70	79
Smart meters	10	–
Retail settlement variance accounts	–	11
Other	2	4
Total regulatory assets	311	400
Regulatory liabilities:		
Deferred pension	382	449
Export and wheeling fees	49	32
Transmission earnings sharing	34	–
Retail settlement variance accounts	2	–
Other	6	14
Total regulatory liabilities	473	495

Regulatory Assets

Regulatory Asset Recovery Account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $20 million (2005 – $20 million). In addition, related financing charges would have been higher by $3 million (2005 – $7 million).

Regulatory Asset Recovery Account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $16 million. In addition, related financing charges would have been higher by $5 million.

Employee Future Benefits Other than Pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of two years (2005 – three years) and does not earn a return. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $42 million (2005 – $42 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower and operation, maintenance and administration expense would have been higher by $17 million (2005 – $14 million).

Smart Meters

On March 21, 2006, the OEB approved the establishment of deferral accounts for smart meter related expenditures and a monthly customer charge of 30 cents per residential customer was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company has recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In the absence of rate-regulated accounting, the Company's operation, maintenance and administration expense would have been higher by $4 million and revenues would have been higher by $2 million.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid to the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately $12 million (2005 – $38 million), assuming no regulatory deferral of distribution and Inergi LP (Inergi) pension-related amounts. In addition, related financing charges would have been higher by $2 million (2005 – $4 million).

Export and Wheeling Fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of this export and wheeling fee, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006.

Transmission Earnings Sharing

On February 21, 2006, the OEB issued a decision that established an earnings sharing mechanism in which 50% of any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates are set, will be equally split between the Company's shareholder and ratepayers. The excess earnings calculation will be based on the 2006 audited financial statements of Hydro One Networks' transmission business. The application of the earning sharing mechanism will be subject to future OEB review and approval. Any changes resulting from this review will be reflected in results of operations when the OEB renders its decision.

Retail Settlement Variance Accounts

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

Note 9.
Debt

December 31

(Canadian dollars in millions)	2006	2005
Short-term notes payable	60	–
Long-term debt:		
4.15% notes due 2006	–	280
4.20% notes due 2006	–	168
4.30% notes due 2006	–	141
4.45% notes due 2007	282	282
4.55% notes due 2007	73	73
4.10% notes due 2007[1]	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	–
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	350
6.59% notes due 2043	315	315
5.00% notes due 2046	75	–
	5,270	5,084
Less: Long-term debt payable within one year	(395)	(589)
Net unamortized premiums (discounts)	9	(14)
Unamortized hedging losses	(12)	(15)
Long-term debt	4,872	4,466

[1] Step-up coupon, after year three from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2006, the notes had a weighted-average interest rate of 4.2%.

Hydro One has a $750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2007, with a two-year extension option. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's commercial paper program.

The Company issues notes for long-term financing under the medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $1,725 million is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2006, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures (Canadian dollars in millions)	Weighted Average Interest Rate (%)
1 year	395	4.4
2 years	500	4.0
3 years	400	4.0
4 years	400	7.2
5 years	250	6.4
	1,945	5.0
6–10 years	1,050	5.3
Over 10 years	2,275	6.4
	5,270	5.7

Note 10.
Fair Value of Financial Instruments and Risk Management

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31

(Canadian dollars in millions)	2006		2005	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	5,270	5,831	5,084	5,697

[1] The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into derivative agreements, such as forward fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2006, Hydro One did not enter into any such derivative agreements. In 2005, Hydro One terminated forward interest rate swap agreements entered into in 2005 and 2004 and having a total notional principal amount of $150 million, resulting in a loss of $10 million. The loss is being amortized on an annuity basis over the 30-year term of the related debt.

As at December 31, 2006, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of $40 million and a fair value of $nil (2005 – $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2006 or in 2005.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2006, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

Note 11.
Employee Future Benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2006 and 2005 was as follows:

	% of Plan Assets	
December 31	**2006**	2005
Equity securities	**64.6**	60.6
Debt securities	**32.0**	36.2
Other	**3.4**	3.2
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $92 million and $79 million at December 31, 2006 and 2005, respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, the Company contributed $86 million to its pension plan in respect of 2006 (2005 – $83 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on actuarial valuation effective December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2006, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $122 million in 2006 (2005 – $123 million).

Year ended December 31	Pension		Employee Future Benefits Other than Pension	
(Canadian dollars in millions)	**2006**	2005	**2006**	2005
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**5,355**	4,862	**1,143**	966
Current service cost	**106**	83	**33**	26
Interest cost	**267**	277	**58**	57
Benefits paid	**(253)**	(248)	**(36)**	(40)
Plan amendments	**6**	–	**22**	1
Net actuarial (gain) loss	**(70)**	381	**(120)**	133
Accrued benefit obligation, December 31	**5,411**	5,355	**1,100**	1,143
Change in plan assets				
Fair value of plan assets, January 1	**4,713**	4,243	**–**	–
Actual return on plan assets	**571**	630	**–**	–
Benefits paid	**(253)**	(248)	**–**	–
Employer's contributions[1]	**86**	83	**–**	–
Employees' contributions	**17**	16	**–**	–
Administrative expenses	**(11)**	(11)	**–**	–
Fair value of plan assets, December 31	**5,123**	4,713	**–**	–
Funded status				
(Unfunded benefit obligation)	**(288)**	(642)	**(1,100)**	(1,143)
Unamortized net actuarial losses	**645**	1,069	**236**	385
Unamortized past service costs	**25**	22	**25**	6
Deferred pension asset (accrued benefit liability)	**382**	449	**(839)**	(752)
Less: current portion	**–**	–	**36**	36
Deferred pension asset (long-term liability)	**382**	449	**(803)**	(716)

[1] In January 2007, the Company made a contribution of $8 million in respect of 2006 (2006 – $8 million in respect of 2005).

Year ended December 31 (Canadian dollars in millions)	Pension 2006	Pension 2005	Employee Future Benefits Other than Pension 2006	Employee Future Benefits Other than Pension 2005
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**89**	67	**33**	26
Interest cost	**267**	277	**58**	57
Actual return on plan asset net of expenses	**(560)**	(619)	**–**	–
Actuarial (gain) loss	**(70)**	381	**(120)**	133
Plan amendments	**6**	–	**22**	–
Other	**(1)**	–	**(1)**	–
Costs arising in the period	**(269)**	106	**(8)**	216
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**248**	327	**–**	–
Actuarial loss (gain)	**177**	(268)	**149**	(113)
Plan amendments	**(3)**	3	**(19)**	–
Net periodic benefit cost [2]	**153**	168	**122**	103
Charged to results of operations [2]	**42**	23	**75**	64
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**156**	171
Service cost and interest cost	**–**	–	**13**	12
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**(124)**	(133)
Service cost and interest cost	**–**	–	**(10)**	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**6.75%**	7.00%	**–**	–
Weighted-average discount rate	**5.00%**	5.75%	**4.98%**	5.93%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.75%	**2.50%**	2.75%
Average remaining service life of employees *(years)*	**10**	10	**10**	10
Rate of increase in health care cost trend [3]	**–**	–	**4.40%**	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	**5.25%**	5.00%	**5.24%**	4.98%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.50%	**2.50%**	2.50%
Rate of increase in health care cost trend [4]	**–**	–	**4.40%**	4.40%

[2] The Company follows the cash basis of accounting. During 2006, pension costs of $86 million (2005 – $83 million) were attributed to labour, of which $42 million (2005 – $23 million) was charged to operations, $34 million (2005 – $32 million) was capitalized as part of the cost of fixed assets, and $10 million (2005– $28 million) was attributed to a regulatory asset.

[3] 7.87% in 2006 grading down to 4.40% per annum in and after 2014 (2005 – 8.47% in 2005 grading down to 4.40% per annum in and after 2014).

[4] 8.69% in 2007 grading down to 4.40% per annum in and after 2014 (2005 – 7.87% in 2005 grading down to 4.40% per annum in and after 2014).

Note 12.
Environmental Liabilities

December 31

(Canadian dollars in millions)	2006	2005
Environmental liabilities, January 1	79	89
Interest accretion	5	5
Expenditures	(17)	(14)
Revaluation adjustment	3	(1)
Environmental liabilities, December 31	70	79
Less: current portion	(15)	(15)
	55	64

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – $15 million; 2008 – $14 million; 2009 – $12 million; 2010 – $10 million; 2011 – $7 million; and thereafter – $31 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

Note 13.
Share Capital

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2006, preferred dividends in the amount of $18 million (2005 – $18 million) and common dividends in the amount of $332 million (2005 – $273 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

Note 14.
Related Party Transactions

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2006 includes $1,206 million (2005 – $1,276 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2006 includes $127 million (2005 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2006 includes $21 million (2005 – $21 million) related to these services.

In 2006, Hydro One purchased power in the amount of $2,183 million (2005 – $2,095 million) from the IESO administered electricity market and $38 million (2005 – $36 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2006, Hydro One incurred $9 million (2005 – $7 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $15 million (2005 – $11 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2006 and 2005.

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2006	2005
Accounts receivable	114	116
Accounts payable and accrued charges	(230)	(263)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $195 million (2005 – $213 million).

Note 15.
Consolidated Statements of Cash Flows

For the purposes of the consolidated statements of cash flows, "cash and cash equivalents" refers to the balance sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2006	2005
Accounts receivable (increase) decrease	(149)	87
Materials and supplies increase	–	(9)
Accounts payable and accrued charges (decrease) increase	(39)	68
Accrued interest increase (decrease)	6	(1)
Long-term accounts payable and accrued charges decrease	(7)	(3)
Employee future benefits other than pension increase	87	62
Other	10	(10)
	(92)	194
Supplementary information:		
Interest paid	302	300
Payments in lieu of corporate income taxes	252	210

Note 16.
Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by the OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

Note 17.
Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2006, and in total thereafter are as follows: 2007 – $110 million; 2008 – $98 million, 2009 – $94 million; 2010 – $91 million; 2011 – $87 million; and thereafter – $16 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2006, the Company provided prudential support, using a combination of bank letters of credit of $22 million (2005 – $21 million) and parental guarantees of $275 million (2005 – $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2006, Hydro One had bank letters of credit of $93 million (2005 – $82 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – $5 million; 2008 – $5 million; 2009 – $4 million; 2010 – $1 million; 2011 – $nil; and thereafter – $1 million.

Note 18.
Segment Reporting

Hydro One has three reportable segments:

— The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;

— The distribution business, which comprises the core business of delivering and selling electricity to customers; and

— The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	–	2,221	–	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823
2005				
Segment profit				
Revenues	1,310	3,085	21	4,416
Purchased power	–	2,131	–	2,131
Operation, maintenance and administration	353	413	26	792
Depreciation and amortization	246	236	5	487
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	711	305	(10)	1,006
Financing charges				325
Income before provision for payments in lieu of corporate income taxes				681
Capital expenditures	349	338	4	691

December 31 (Canadian dollars in millions)	2006	2005
Total assets		
Transmission	6,965	6,827
Distribution	5,170	4,902
Other	99	92
	12,234	11,821

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

Note 19.
Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2006 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 (Canadian dollars in millions)	2006	2005	2004	2003	2002
Statement of operations data					
Revenues					
Transmission	**1,245**	1,310	1,262	1,298	1,317
Distribution	**3,273**	3,085	2,874	2,734	2,682
Other	**27**	21	17	26	32
	4,545	4,416	4,153	4,058	4,031
Costs					
Purchased power	**2,221**	2,131	1,987	1,872	1,858
Operation, maintenance and administration[1]	**880**	792	771	795	832
Depreciation and amortization	**515**	487	480	454	411
	3,616	3,410	3,238	3,121	3,101
Regulatory recovery[2]	**–**	–	91	–	–
Income before financing charges and provision for payments in lieu of corporate income taxes	**929**	1,006	1,006	937	930
Financing charges	**295**	325	331	348	353
Income before provision for payments in lieu of corporate income taxes	**634**	681	675	589	577
Provision for payments in lieu of corporate income taxes	**179**	198	177	193	233
Net income	**455**	483	498	396	344
Basic and fully diluted earnings per common share *(Canadian dollars)*	**4,366**	4,652	4,798	3,779	3,258

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**6,965**	6,827	6,785	6,589	6,638
Distribution	**5,170**	4,902	4,845	4,623	4,694
Other	**99**	92	95	94	90
Total assets	**12,234**	11,821	11,725	11,306	11,422
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,194**	1,341	1,262	1,192	1,894
Long-term debt	**4,872**	4,466	4,613	4,539	3,938
Other long-term liabilities	**1,347**	1,298	1,326	1,284	1,451
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,184**	1,079	887	654	502
Total liabilities and shareholder's equity	**12,234**	11,821	11,725	11,306	11,422

Year ended December 31 (Canadian dollars in millions)	2006	2005	2004	2003	2002
Other financial data					
Capital expenditures					
Transmission	402	349	432	289	260
Distribution	417	338	288	292	286
Other	4	4	7	16	24
Total capital expenditures	823	691	727	597	570
Ratios					
Net asset coverage on long-term debt[3]	1.92	1.93	1.88	1.86	1.90
Earnings coverage ratio[4]	2.67	2.69	2.70	2.43	2.35
Operating statistics					
Transmission					
Units transmitted *(TWh)*[5]	151.1	157.0	153.4	151.7	153.2
Ontario 20-minute system peak demand *(MW)*[5]	27,056	26,219	25,204	24,849	25,629
Ontario 60-minute system peak demand *(MW)*[5]	27,005	26,160	24,979	24,753	25,414
Total transmission lines *(circuit-kilometres)*	28,600	28,547	28,643	28,621	28,492
Distribution					
Units distributed to Hydro One customers *(TWh)*[5]	29.0	29.7	28.5	27.9	27.1
Units distributed through Hydro One lines *(TWh)*[5,6]	44.7	45.6	44.8	44.7	45.1
Total distribution lines *(circuit-kilometres)*	122,460	122,118	121,736	121,285	120,767
Customers	1,293,396	1,273,768	1,258,925	1,238,748	1,219,614
Total regular employees	4,295	4,189	4,118	3,967	3,933

1 Operation, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program.

2 As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act*, 2002, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

3 The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

4 The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

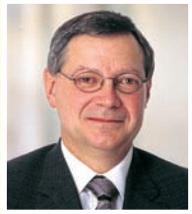
5 System-related statistics include preliminary figures for December.

6 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Board of Directors (as at December 31, 2006)

Rita Burak[2]
Chair of the Board
of Directors,
Hydro One Inc.

Sami Bébawi[5,6]
Executive Vice President,
Office of the President,
President, Socodec Inc.,
SNC-Lavalin Group Inc.



Murray J. Elston[1,3,5]
President and CEO,
Canadian Nuclear
Association

Don MacKinnon[5,6]
President, Power
Workers' Union

Eileen A. Mercier[1,2,4]*
Corporate Director
Resigned March 16, 2007

Walter Murray[1,3,4]
Corporate Director

Kathleen O'Neill[1,2,3,4]*
Corporate Director
Resigned January 24, 2007

Douglas E. Speers[1,4,6]
Chairman and Director,
Emco Corporation

Kenneth D. Taylor[5,6]*
Chair, Taylor and
Ryan Inc.
Resigned February 27, 2007

Blake Wallace, Q.C.[2,3,5]*
Vice President and
Director, Murray
& Company
Resigned February 26, 2007

Board Committees

[1] Audit and Finance Committee

The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met five times in 2006.

[2] Corporate Governance Committee

The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandates of each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2006.

[3] Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met eight times in 2006.

[4] Information Technology Committee

The Information Technology Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met three times in 2006.

[5] Regulatory and Environment Committee

The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met five times in 2006.

[6] Health and Safety Committee

The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2006.

* Effective March 30, 2007, the following directors were elected to the Board of Directors of Hydro One Inc. by our shareholder: Kathryn Bouey; Laura Formusa; Michael Mueller; Robert Pace; and Gale Rubenstein in place of Eileen Mercier, Kathleen O'Neill, Tom Parkinson, Honourable Bob Rae, Kenneth Taylor and Blake Wallace, who have resigned as members of the Board. As well, the number of directors of the Corporation was reduced from 12 to 11.

Corporate Information

Corporate Address
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investor.relations@HydroOne.com

Media Inquiries
(416) 345-6868
1-877-506-7584

Customer Inquiries
Power outage and
emergency number:
1-800-434-1235

Residential, farm &
small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
Ernst & Young LLP

Concept and Design: THE WORKS www.worksdesign.com

Making life better for electrical burn patients

In 2006, Hydro One, Sunnybrook Health Sciences Centre and St. John's Rehab Hospital announced the Hydro One Chair in Electrical Injury, a permanently endowed fund to support clinical and academic leadership in the field of electrical injury. Over the next five years, Hydro One has committed $500,000 to push forward research and treatment of electrical burn patients.

"Electrical burns are not very well understood and often the damage they do goes unseen and undiagnosed," said Dr. Joel Fish, Medical Director at the Ross Tilley Burn Centre at Sunnybrook Health Sciences Centre. "The research enabled by this funding will do a great deal to improve treatment and rehabilitation for burn patients."

Since 2003, Hydro One and Sunnybrook Health Sciences Centre have worked together to make the expertise of the Ross Tilley Burn Centre available through the hospital's teleconference capability and the NORTH Network telemedicine network to electrical burn patients across Ontario and Canada. Every year, between 600 and 800 workplace electrical burns occur in Canada, the vast majority of them to workers outside of the electricity sector.

The proper care and treatment for electrical burn patients is important not only to those of us in the electrical industry, but also to workers in every sector.

hydroOne

Sunnybrook
ROSS TILLEY BURN CENTRE

Dr. Joel Fish
Medical Director, Ross Tilley Burn Centre

Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value.

Hydro One Inc.

483 Bay Street
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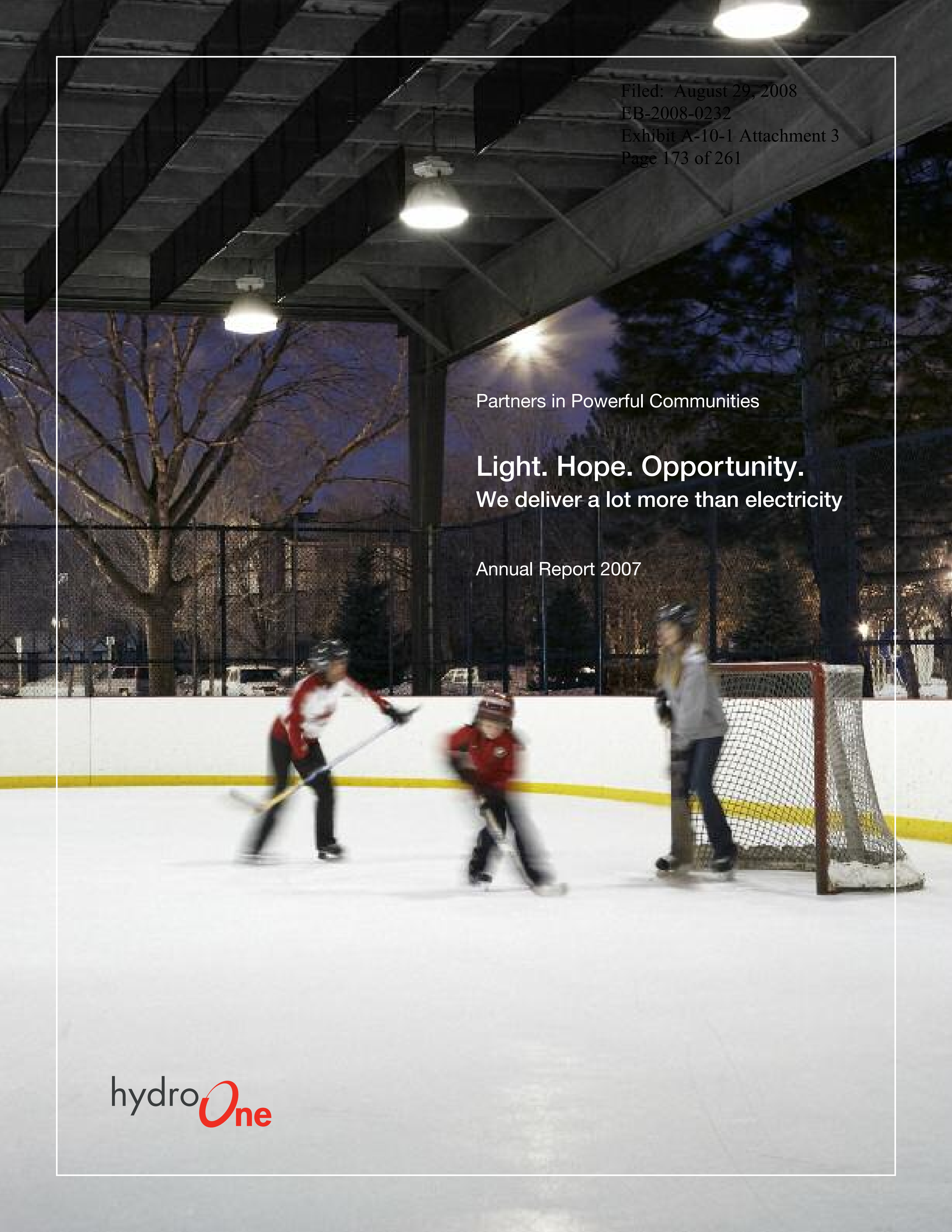


Partners in Powerful Communities

Light. Hope. Opportunity.

We deliver a lot more than electricity

Annual Report 2007

hydro One

Our mission is to be an efficient and dynamic electricity transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on our people and creating shareholder value.

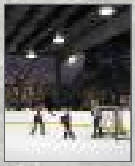
Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom services.

Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our excess fibre-optic capacity to business customers. This business represents less than 1% of our total assets.



Cover image:
Healthy, powerful communities require a reliable, safe and secure electricity system. Hydro One is working to connect Ontario communities to the electricity necessary for a vibrant and growing economy.

95% satisfaction

Overall customer satisfaction levels for Large Transmission Customers reached 95% this year, an increase of 10% from 2006.

$839,728 raised

Our staff raised $839,728 for charities of their choice, through the 9th Annual Hydro One Employees' and Pensioners' Charity Campaign.

75,044,621 kWh saved

Hydro One customers are saving more than 75 million kWh from energy efficient products purchased during the spring Every Kilowatt Counts program.

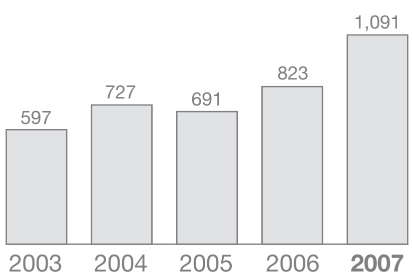
Consolidated financial highlights and statistics

Year ended December 31 (Cdn $ millions)	**2007**	2006	Change	% Change
Revenues	**4,655**	4,545	110	2
Purchased power	**2,240**	2,221	19	1
Operating costs	**1,516**	1,395	121	9
Net income	**399**	455	(56)	(12)
Net cash from operations	**1,141**	909	232	26
Average annual Ontario 60-minute peak demand (MW)[1]	**22,988**	22,650	338	1
Distribution – units distributed to our customers (TWh)[1]	**30.2**	29.0	1.2	4

[1] System-related statistics include preliminary figures for December.

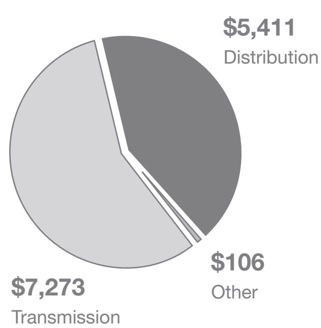
Capital Expenditures

(Cdn $ millions)



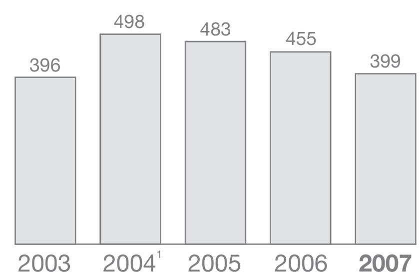
Total Assets

December 31, 2007
(Cdn $ millions)



Net Income

(Cdn $ millions)



[1] Net income includes a one-time regulatory recovery of $91 million.

Letter from the Chair

Rita Burak
Chair

When I was appointed to the position of Chair in 2003, Ontario's electricity sector was still grappling with the impact of significant restructuring. Five years later, the sector has evolved and matured with a clear mandate and we have a firm understanding of our role in Ontario. We are the stewards of a strategic and vital public asset. We work so that Ontario can.

2007 saw Hydro One deliver on its commitments: earn solid returns for our shareholder, provide exceptional service to our customers and make investments in the electrical infrastructure vital to the continued delivery of safe, reliable electricity to the people of Ontario.

The Company's net income in 2007 decreased by $56 million, or 12%, to $399 million compared to 2006. This decrease reflects lower transmission tariff revenues resulting from changes to transmission tariffs and increased expenditures required to operate and maintain our transmission and distribution systems.

Hydro One made critical investments both in transmission and distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Total capital and operation, maintenance and administrative expenditures for 2007 were $2,086 million.

In the past three years Hydro One has begun a major new construction phase and this will continue in the years and decades ahead. The projects planned with our industry partners at the Ontario Power Authority and the Independent Electricity System Operator are fundamental to delivering the safe, reliable electricity a growing Ontario needs.

We are the stewards of a strategic and vital public asset. We work so that Ontario can.

At this critical juncture, our ability to arrange sufficient and cost-effective financing is vital. This is facilitated by our strong and stable long-term credit rating that reflects the confidence of rating agencies and investors in the performance, management and future of the Company.

In the past few years, all Boards of Directors have spent tremendous energy on the governance and compliance functions; the Hydro One Board has also made these issues a top priority. The good governance of Hydro One is essential to our shareholder, the Province of Ontario, our bond holders and the people of Ontario who depend upon Hydro One to operate in their interest. We take our financial obligations seriously. Our financial controls and disclosure practices are solid and under regular external scrutiny. My fellow Board members and I are more focused than ever on ensuring that the Company operates in a way that delivers maximum value to the people of Ontario.

While we've steadfastly carried out our oversight function, we have also put strong emphasis on making a strategic contribution to ensure that the Company benefits from the Board's collective skills and experience.

The Board will continue to provide sound, strategic direction to the Company and is confident in the management team's ability. Hydro One paid its shareholder, the Province of Ontario, dividends of $325 million and recorded $205 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province.

On behalf of the Board of Directors, I would like to thank Hydro One's management and employees for their valuable contribution and dedication to their task. The Board looks forward to continuing the work of the Company in providing a safe, reliable, affordable electricity delivery system for the people of Ontario. After a 35-year career in public service, I leave this post confident that Hydro One and Ontario's electricity delivery system are in capable hands. It has been a great honour to serve.

Rita Burak
Chair

Laura Formusa
President and
Chief Executive Officer

Letter from the President and CEO

The people of Ontario depend upon Hydro One to deliver a precious resource to them. And, as stewards of Ontario's electricity delivery system, our role is clear: we must maintain operational excellence while working with our partners to ensure that electricity can be delivered safely, reliably and affordably for generations to come.

Hydro One is more than just wires, towers and poles traversing this great province. We are good neighbours, safe operators and partners in powerful communities.

Hydro One employees are among the best in North America, and our performance this year reflected that fact. One of the most important measures of our performance is the satisfaction of our customers. And in 2007, our largest customers told us that they were more satisfied with our performance than ever before. Like safety, customer satisfaction is part of every conversation, every project and every day at our Company.

With major refurbishment, growth and construction underway and planned for the years ahead, it's a dynamic and challenging period for our Company. I am confident that Hydro One will continue to successfully deliver the electricity that Ontario needs. I am also confident that our efforts in energy efficiency and demand management will foster a culture of conservation in this province.

In addition to the stations and many thousands of kilometres of lines that we maintain, we have been very busy with major construction projects across Ontario. Our work crews completed the construction of a major underground cable in Toronto to improve supply reliability and flexibility. Significant progress was also made in 2007 on the interconnection with Quebec to improve Ontario's access to clean sources of electricity.

Hydro One is more than just wires, towers and poles traversing this great province. We are good neighbours, safe operators and partners in powerful communities.

The construction of infrastructure projects is only a small part of our task. To be a successful utility requires partnering with the public in a way that was not always part of the model in the past.

I believe that *how* we work with customers, *how* we treat communities and *how* we run our business are just as important as *what* we do.

With a generation of energy workers on the verge of retirement, we have embarked on an ambitious program to renew and enhance our workforce. Our efforts to create value for our shareholder and the people of Ontario are driven by the men and women who work for Hydro One. Maximizing their potential, developing future leaders and recruiting the best and brightest employees will determine Hydro One's strength in the years ahead. In that regard, Hydro One has taken a leadership role by partnering with four Ontario colleges to fund curriculum development to ensure that graduates will leave school with the skills our industry requires.

In 2007, we were also recognized for our focus on diversity. We are proud of receiving an award and believe that creating a diverse workplace is essential to our future and will bring the very best people to Hydro One. Our efforts are ensuring that we're attracting employees who reflect Ontario's communities.

Hydro One's 4,600 employees live and work in almost every community in Ontario. Through employee and pensioner fundraising, they contribute generously to charities of their choice. In 2007, Hydro One launched the PowerPlay grants program to fund projects in our communities for healthy and safe children's sports and play facilities.

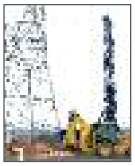
I'd like to thank the Hydro One Board of Directors for its guidance and oversight. Their contribution is critical to the success of our Company. I'm proud to work with the employees of Hydro One, employees who are dedicated, hard-working and aware of how much Ontario counts on them. We all know that the towers, stations, wires and poles we build, operate and maintain are more than just infrastructure, more than just our business. They deliver more than electricity. They deliver light, hope and opportunity.

Laura Formusa
President and Chief Executive Officer

To meet the growing needs of Ontario's communities, Hydro One is engaged in its largest infrastructure renewal initiative in more than two decades.

Connecting Clean and New Renewable Energy

To meet southern Ontario's growing energy needs, Hydro One intends to build a 180-km, double-circuit transmission line from the Bruce Power facility near Kincardine to the Milton Switching Station. With a projected in-service date of 2012, the completed line will deliver 3,000 MW of clean electricity. In 2007, Hydro One held a series of public meetings and made a concerted effort to inform and work with communities directly affected by the project.



Connecting Energy in Ontario and Quebec

Hydro One is working with Hydro-Québec TransÉnergie to expand transmission capacity between Ontario and Quebec and provide Ontarians with greater access to a reliable supply of renewable energy. A new line is being built between transformer stations in Ottawa and Masson, Quebec. With an expected in-service date of spring 2009, the new interconnection will increase Ontario's capacity to transfer power from or to Quebec by 1,250 MW.

Walter Ryan, Hydro One cable technician, examines the circuits 30 metres under Toronto's Front Street.

Building infrastructure. Creating opportunity.

To ensure that Ontario's businesses and communities continue to enjoy the benefits of reliable, safe and secure electricity, Hydro One has embarked on a province-wide effort to enhance and expand our transmission infrastructure.

As stewards of the province's transmission system for more than a century, we've learned through experience that the key to a successful construction project is first building a strong relationship with the communities we serve. The recently completed underground transmission line, connecting two transformer stations in downtown Toronto, exemplifies Hydro One's approach of identifying vital needs, seeking stakeholder input and then developing innovative technical solutions.

Downtown Toronto is the heart of Canada's business and financial sectors and its access to a secure, reliable supply of energy has national implications. An analysis of the area's energy requirements made it clear that the existing transmission grid needed improvement. To improve both flexibility and functionality, Hydro One built two underground cables, spanning 2.2 km, between the St. Lawrence Market and the Rogers Centre to connect two transformer stations.

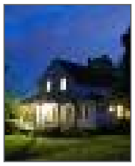
In the past, building a tunnel 30 metres below street level would require tearing up streets and disrupting traffic for months – a particularly unattractive prospect for the country's largest and busiest city. However, an innovative earth-boring machine enabled Hydro One to dig the tunnel without significant disruption to local business activities and with minimal impact on traffic.

Throughout the process, Hydro One kept stakeholders informed through public meetings and regular project updates published on our website. The project was completed on time and the circuit became operational in December 2007.

335 municipalities

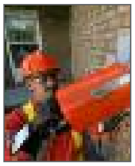
Hydro One's distribution network serves 335 of the 445 municipalities in Ontario.

Hydro One is committed to delivering the clean, reliable, renewable energy Ontario needs to meet the challenges of the 21st century.



Creating a Conservation Culture

Our conservation and demand management programs have reached 1.1 million participants to date. These programs combine to save 272 million kWh annually, enough energy to power 23,000 homes for one year. For more conservation and demand management program results, take a look at the inside back cover.



Doing the Smart Thing Is Rewarding

In September 2007, an international panel of judges named Hydro One the winner of the Utility Planning Network's 2007 Metering Award – Automated Meter Reading Initiative category. The award was given in recognition of Hydro One's efforts to support the province's Smart Meter Program. As of December 31, 2007, Hydro One teams had installed 288,000 smart meters, which allow for the sophisticated metering and management of power use and will ultimately facilitate time-of-use rates when they come into effect.

Linda Heinzle tends to a month-old calf while George keeps on top of feeding time at Terryland Farms in St. Eugene, Ontario.

Sustainable. Renewable. It's our energy future.

Ontario's energy needs are growing and changing. The impact of climate change on the environment has made it clear that the province and its people must take a new approach to energy use and supply management.

Hydro One is partnering with other leaders in the energy sector on a number of innovative measures aimed at reducing energy use and incorporating new sources of renewable energy into Ontario's electricity system.

Over the past year, Hydro One made great strides to deliver on the Province of Ontario's Renewable Energy Standard Offer Program (RESOP). Targeted at small, local suppliers, RESOP supports the development of renewable energy sources, such as solar, wind, biogas, biomass and water power, by offering participants price stability and a 20-year contract. Hydro One reviews the feasibility of all proposals and connects approved suppliers to our distribution system where possible.

In 2007, George and Linda Heinzle became the first suppliers of biomass energy connected to Hydro One's transmission system as part of RESOP.

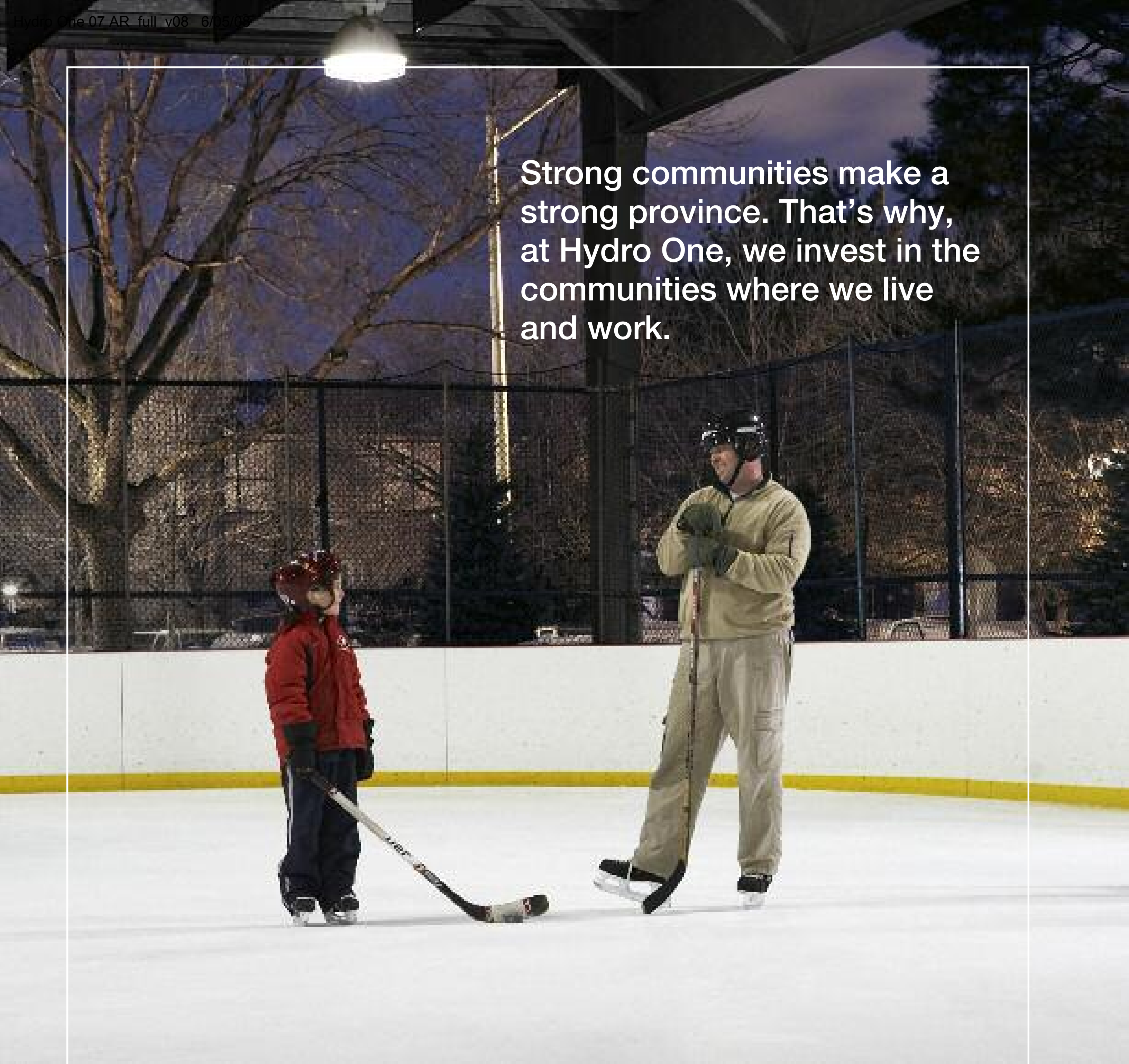
The Heinzles own Terryland Farm, a 130-head dairy operation located east of Ottawa. Like all dairy farms, it produces a significant amount of renewable biomass. But where others saw waste, George and Linda recognized a wasted resource. The Heinzles can generate 700 kWh per day, enough to power an average household for almost one month.

Connecting the Heinzles to the grid was an important first step. As more small providers of renewable energy connect to the electricity system, they will make a big contribution to the system's long-term reliability and diversity of Ontario's power supply.

8,000 MW

In 20 years, Ontario's renewable energy supply is expected to increase by 8,000 MW, enough to meet almost one third of the province's current electricity demand.

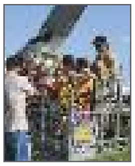
– according to the Ontario Power Authority's *Supply Mix Advice Report*.



Strong communities make a strong province. That's why, at Hydro One, we invest in the communities where we live and work.

Supporting First Nations Literacy

In Ontario's north, Hydro One is working with local communities to preserve First Nations' languages and traditions. As a major sponsor of the Kwayaciiwin Literacy Program, we are helping to ensure the ongoing vitality and relevance of aboriginal languages. Offered in seven different northern communities, the program starts in the earliest grades, providing kindergartners and their teachers with special books and teaching materials. The goal of the Kwayaciiwin program is to graduate students who are literate and fluent in both Anihshiniimowin and English.



Powering the International Plowing Match

Since 2001, Hydro One has provided electricity to the International Plowing Match (IPM), Canada's largest agricultural exhibition. The IPM offers an excellent opportunity for Hydro One staff to meet Ontario's agricultural community and discuss smart meters, conservation and other Hydro One programs. By meeting our customers face-to-face, we can better understand their needs and what works for them. This means we can deliver programs and services that help them use electricity as efficiently as possible.

Hydro One is improving children's recreation and play facilities across Ontario through its new PowerPlay grants program.

Partners in powerful communities.

From busy urban centres to the towns and villages of the north, Hydro One and its employees are committed to building strong, healthy communities across Ontario. Through our employees' volunteer efforts and charitable grants and sponsorships, Hydro One supports a wide range of community-building initiatives.

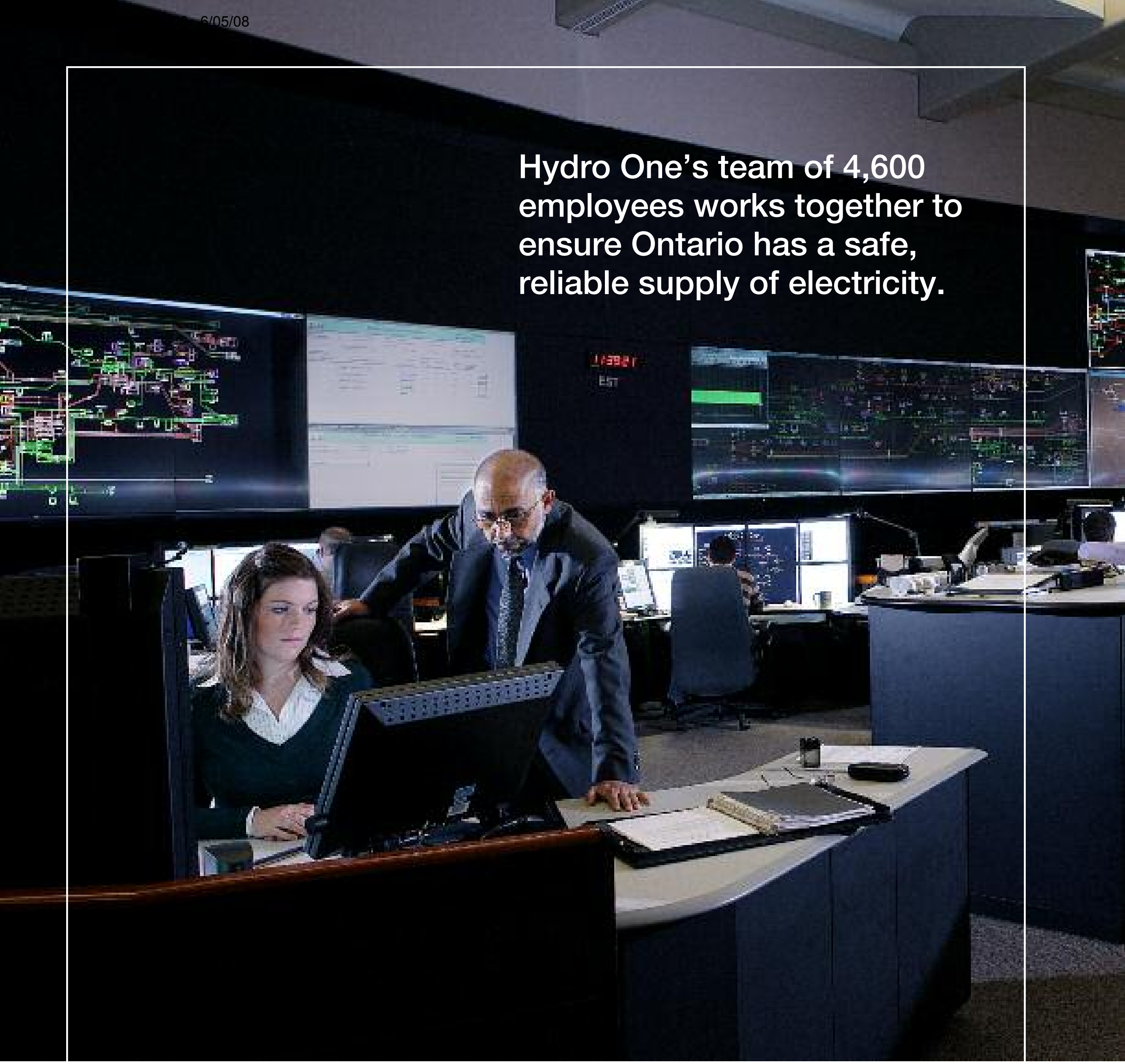
In August 2007, Hydro One announced the launch of PowerPlay, a new grants program to support and enhance children's sports and recreation facilities. PowerPlay offers grants of up to $25,000 for projects for community centres, indoor or outdoor ice rinks, playgrounds, splash pads and sports fields – places where kids can participate in community sports, stay healthy and active and have fun. The program is open to municipalities and registered charities where Hydro One is the local electricity supplier.

Last year, *Corporate Knights*, the world's largest circulation magazine with an explicit focus on corporate responsibility, named Hydro One as one of Canada's Top 50 Corporate Citizens. Rankings are based on a review of environmental, social and governance indicators as well as key performance indicators for specific industry sectors. Hydro One was ranked 26 out of the top 50 and third among utilities in Canada.

$500,000

Hydro One has committed $500,000 to advance research and treatment of patients with electrical burns, through the Ross Tilley Burn Centre at Sunnybrook Health Sciences Centre.

6/05/08



Hydro One's team of 4,600 employees works together to ensure Ontario has a safe, reliable supply of electricity.

Making Solid Progress in Customer Satisfaction

Customer satisfaction levels increased substantially this year. Overall satisfaction for Large Transmission Customers increased by 10% to 95% this year and overall satisfaction for Large Distribution Customers increased by 6% to reach 90%. These increases are due to a concerted effort by each and every employee in our Company to address customer issues quicker. Our goal is to achieve 90% satisfaction or better for all customers in the next five years.

Building Tomorrow's Workforce

In a few years, more than 30% of Hydro One's workforce can retire. That's why Hydro One is taking action to attract future employees by partnering with four Ontario colleges: Algonquin, Georgian, Mohawk and Northern. In addition to donating equipment and establishing scholarships and bursaries, Hydro One's professionals will help develop curriculum for the program. The partnership will make talented young people aware of the many opportunities available in the electrical transmission and distribution sector. Hydro One is also sponsoring similar programs at the University of Western Ontario, McMaster University and Ryerson University.

Kristy Dennis, controller-trainee, Farooq Qureshy, transmission system planner, and Dean Edwards, line maintainer, don't all work at the Ontario Grid Control Centre, but they do work together to meet Ontario's electricity needs.

Our greatest power is our people.

Every day the women and men of Hydro One go to work with one goal in mind: the safe, reliable operation of Ontario's electricity system. Stewardship of Ontario's electricity delivery system demands a diverse workforce with a wide variety of skills, talents and training. We need people who are not only experts in their respective fields but who are also able to contribute as members of an integrated team. System planners, station maintenance technicians, foresters, line maintainers, system operators and engineers all have to cooperate to keep Ontario strong.

Like many large employers, Hydro One is facing a massive demographic shift. Within five years, 30% of our workforce can retire. In 2007, we focused on strategies to facilitate knowledge transfer to the next generation of employees. Our New Grad initiative recruits top university graduates into an intensive two-year program that rotates them through a range of our operations.

Hydro One's apprenticeship program has steadily expanded in the last four years, with 774 apprentices joining trades such as line maintenance, electrical forestry, station maintenance and others. Hydro One's rigorous training sets the industry standard for the province and produces safe and productive workers that Ontarians can rely on.

Initiatives like our new pilot partnership with the Sioux Lookout Aboriginal Management Board and the Power Workers' Union, launched to attract new Aboriginal employees, demonstrate Hydro One's commitment to reflect the communities where we live and work.

774

Hydro One has taken on 774 apprentices in the last four years.

Hydro One Senior Management

Laura Formusa
President and
Chief Executive Officer,
Hydro One Inc.

Joe Agostino
General Counsel

Myles D'Arcey
Senior Vice-President,
Customer Operations

Steve Dorey
Vice-President,
External Relations

John Fraser
Vice-President, Internal Audit
and Chief Risk Officer

Tom Goldie
Senior Vice-President,
Corporate Services

Peter Gregg
Vice-President,
Corporate and
Regulatory Affairs

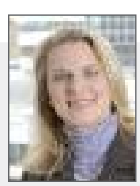
Rick Kellestine
Vice-President and
Executive Advisor

Carmine Marcello
Vice-President,
Corporate Projects

Nairn McQueen
Vice-President,
Engineering and
Construction Services

Geoff Ogram
Vice-President,
Asset Management

Wayne Smith
Vice-President,
Grid Operations



Beth Summers
Executive Vice-President and
Chief Financial Officer

Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2007 and 2006.

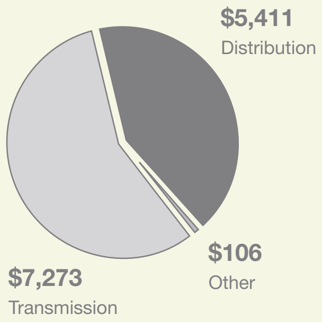
Overview

We are wholly owned by the Province of Ontario (the Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2007, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from one location, our Ontario Grid Control Centre in Barrie, Ontario. It operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2007, we earned total transmission revenues of $1,242 million primarily by transmitting approximately 152 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our transmission business is our largest business segment, representing approximately 57% of our total assets.

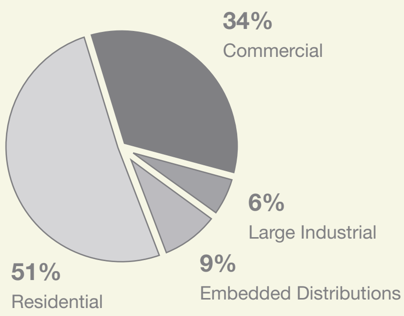
Total Assets
December 31, 2007
(Cdn $ millions)



Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

2007 Distribution Revenues



Other

Our other business segment contributed revenues of $31 million in 2007 and has assets of about $106 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2007, aligned with retaining and building public confidence and trust, we maintained our strategic focus on our core operations and built upon our accomplishments. Consequently, we have moved closer to achieving our goals to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder for delivering superior value, while striving to attract, develop and retain productive employees.

We seek to achieve these goals by continuing to implement the following strategies:

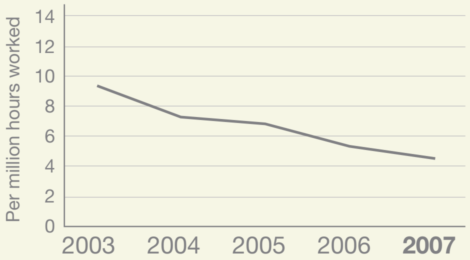
- *Stewardship:* Retain and build the public trust placed in us to ensure the safe, reliable and efficient delivery of electricity.
- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on eliminating serious injury and "near misses" in high potential harm categories of work.
- *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers, acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.
- *Reliability:* Enhance the reliability of our transmission and distribution systems through our productive and cost effective work programs. In transmission, we are proactively developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.
- *Employees:* Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We met or exceeded our challenging 2007 objectives, improving in a number of areas over 2006, and are moving towards achieving our strategic goals.

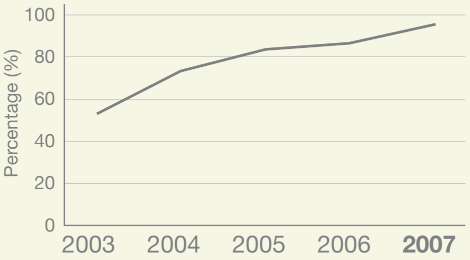
The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to eliminate serious injuries. Accordingly, we measure our Serious Incident Rate to identify possible situations that may increase the risk of injury. These incidents include electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. As shown in the accompanying chart, we had 4.4 serious incidents per million hours worked in 2007, which is 15% lower than 2006, 34% lower than 2005, and 39% lower than 2004. Going forward, we will continue to stress the importance of safety through a sustained cultural change and a continued focus on people and the work environment. This involves an emphasis on strong leadership, understanding and leveraging human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments and further use of decision analysis tools to reduce human error and its consequences.

Serious Incident Rate



Customer satisfaction is also vital to our success. In 2007, we exceeded our overall target for customer satisfaction levels. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 86% to 95% satisfied, as compared to 2006. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our residential and small business customers and survey results show an overall satisfaction level of 82%, which remains consistent with 2006 results. We achieved our overall target for generator customer satisfaction. Within this category, we met our satisfaction target for transmission connected generators, but did not achieve our target for distribution connected generators. Addressing the concerns identified will be an area of focus in 2008. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

Large Transmission Customer Satisfaction



We aim to retain and build public confidence and trust in our operations, as stewards of the province's electricity grid. In 2007, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2007, we met our annual reliability targets and achieved improvements over 2006. Our continued commitment to the people of Ontario has been recognized by *Corporate Knights*, an independent media magazine, focused on promoting and reinforcing sustainable development in Canada, as one of Canada's Top 50 Corporate Citizens, ranking third among utilities. The ranking was based on environment, social and governance indicators, and our conservation and demand management (CDM) and Smart Meter Programs were cited as key factors in the recognition. In addition, *Corporate Knights* recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada.

Given the retirement profile of our employees, we are entering into a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. As part of a comprehensive strategy to meet our staffing needs well into the future, we entered into a partnership with four community colleges of applied art and technology to attract and educate the future employees of the electricity transmission and distribution sectors. Through this partnership, we will contribute towards scholarships, program development and equipment for programs that will train people for technical, technological and trades positions in the electricity sector.

Our financial performance and the business environment in which we operate are taken into consideration in both our short-term and long-term credit ratings. In March 2007, Standard & Poor's Rating Services Inc. (S&P) assigned a positive outlook to our long-term "A" credit rating from stable, attributing the improvement to lower business risk for the sector as a whole. In November, S&P issued a commentary report which reaffirmed our assigned positive outlook while noting a steady improvement in our business risk profile. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

Regulation

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004,* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval on August 29, 2007. The plan's estimated 20-year capital program will be directed toward initiatives required to deliver electricity to Ontario consumers. OEB approval is expected in the Fall of 2008.

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management programs. This coordination furthers initiatives undertaken by individual local distribution companies (LDCs), including our distribution businesses, as a result of distribution tariff rate increases approved in 2005. Our CDM programs funded through the OPA in 2007 amounted to approximately $6 million and our programs funded through distribution rates since 2005 amounted to approximately $41 million. The overall goal of the CDM programs, under the IPSP, is to reduce provincial demand by 6,300 MW by 2025.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the development of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use rates that are presently voluntary. In 2007, we deployed over 260,000 smart meters, exceeding our 2007 target of approximately 240,000 meters, and bringing the cumulative number of installations under our Smart Meter Program to approximately 288,000. We are continuing the deployment of smart meters (see the Future Capital Expenditures chart on page 30).

Transmission Rates

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced its decision to apply an earnings sharing mechanism (ESM) to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period ending January 1, 2006 until new transmission rates were set. Consequently, 50% of our excess earnings recovered from customers were deferred as a regulatory liability.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks). On March 30, 2007, prior to its decision on our transmission rate application, the OEB issued a decision ordering that the ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. However, the decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of LDCs. Further, the OEB approved final amounts and disposition treatments for certain regulatory accounts including the RDDA, ESM and export and wheeling fees liabilities, as well as the transmission market ready regulatory asset. The RDDA and ESM will be refunded to customers over the 14-month period from November 1, 2007 to December 31, 2008, while the export and wheeling fees liability and transmission market ready regulatory asset will be factored into rates over the four-year period ending December 31, 2010.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007 the OEB approved new UTRs for implementation on November 1, 2007 through to December 31, 2008. The new rates fully reflect the approved changes to our revenue requirement and charge determinants and are, on average, 12% lower than previously approved rates. The new rates should result in approximately a 1% decrease in the average customer's total electricity bill. We anticipate the OEB will reset UTRs on January 1, 2009, at which time we anticipate our revenue requirement allocation from UTRs will increase to reflect the full repayment to customers of the ESM and RDDA. To achieve the necessary funding in support of the infrastructure required, we plan to submit a transmission rate application for 2009 to 2010 transmission rates in the Summer of 2008.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges.

Distribution Tariffs

In August 2005, we filed a distribution rate application seeking approval for an increase in the 2006 revenue requirements for our distribution businesses operated through Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton). On April 12, 2006, the OEB announced its decisions regarding these applications and, on the basis of the written and oral evidence submitted, it approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

In 2006, the OEB commenced the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Our subsidiaries, Hydro One Networks and Hydro One Brampton, applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved our submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

As our subsidiary Hydro One Networks was among 25 LDCs selected for rebasing in 2008, we submitted the revenue requirement portion of our 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64% for 2008. The requested distribution rate increase amounts to a net average increase of less than 1% on the average customer's total bill. On December 18, 2007, we filed the details of our cost allocation and rate design proposals, which include a plan to reduce the number of customer rate classes and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the latter part of 2008.

On August 2, 2007, the OEB initiated a consultation on the development of the principles and methodology for the third generation IRM. This consultative process will culminate with the issuance of an OEB report expected in mid-2008 that will be used to adjust rates starting in 2009, for those LDCs, including our subsidiary Hydro One Networks, whose 2008 rates will be rebased. On November 1, 2007, Hydro One Brampton filed its application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies. The distribution rates of our subsidiary, Hydro One Brampton, will be rebased in 2010.

Smart Meter Program

In March 2006, the OEB approved a monthly rate of 27 cents and 28 cents per metered customer, effective May 1, 2006, as initial funding for the required investment in smart meters for our subsidiaries Hydro One Networks and Hydro One Brampton, respectively. As a result, expenditures in excess of recoveries were recorded as a regulatory asset, with disposition to be established at a later date. In April 2007, as part of the OEB decision regarding the 2007 distribution rate applications made by Hydro One Networks and Hydro One Brampton, the OEB approved an amount of 93 cents and 67 cents, respectively, per month per metered customer for smart meters, for implementation effective May 1, 2007.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the approved minimum functionality for advanced metering infrastructure incurred by our subsidiaries Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets, and instead, are now classified as capital or are charged to results of operations. Expenditures determined to be above the minimum functionality for our subsidiary Hydro One Networks have been brought forward for review in our 2008 cost of service rate application. Hydro One Brampton will bring these expenditures forward in its 2010 cost of service application.

Results of Operations

Revenues

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006	$ Change	% Change
Transmission	**1,242**	1,245	(3)	–
Distribution	**3,382**	3,273	109	3
Other	**31**	27	4	15
	4,655	4,545	110	2
Average annual Ontario 60-minute peak demand ***(MW)***[1]	**22,988**	22,650	338	1
Distribution – units distributed to customers ***(TWh)***[1]	**30.2**	29.0	1.2	4

[1] System-related statistics include preliminary figures for December.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Revenues for the year were affected by the OEB's August 16, 2007 decision on our transmission rate application. While the OEB approved all of our work program expenditure requirements, our return on equity was reduced from 9.88% to 8.35% and our deemed capital structure was adjusted from one that included common and preferred shares and debt to a deemed capital structure of 60% debt and 40% common shares. This capital structure is consistent with that approved by the OEB in 2006 which established the capital structure for Ontario's LDCs. The OEB's decision was effective January 1, 2007 and new customer rates reflecting the decision were implemented on November 1, 2007. As a result of the OEB decision, we reduced our 2007 transmission revenues to reflect the approved revenue requirement. Excess amounts collected from customers have been recorded in the RDDA and are being returned to customers through lower rates commencing November 1, 2007. On March 30, 2007, the OEB approved cessation of the ESM effective December 31, 2006 and replaced it with the RDDA. The RDDA and ESM liabilities will be drawn down over the period the new rates are in place and will be reflected in revenue over the 14-month period from November 1, 2007 to December 31, 2008.

Our transmission revenues were lower by $3 million, compared to 2006. The OEB's August 16, 2007 transmission rate decision reduced our revenues by about $53 million. This includes the revenue adjustment associated with recording the RDDA liability and the impact of the new OEB-approved rates effective November 1, 2007. Partially offsetting this decrease was the effect of the OEB's earlier decision to end the ESM effective December 31, 2006, which increased our transmission revenues by about $33 million.

Revenues for the year also reflect higher average peak demands compared to last year, resulting in increased transmission revenues of $23 million and lower other revenues of $6 million.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $109 million, or 3%, in 2007 compared to last year. This change includes the recovery of increased purchased power costs of $19 million as described below under Purchased Power. In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks and Hydro One Brampton, effective May 1, 2006 and May 1, 2007, respectively. These tariff rate increases, which support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers through Ontario, resulted in higher distribution revenues of $45 million during the year. In 2006, rates were approved based on a full cost of service hearing. In 2007, rates were approved based on OEB guidelines that included an incentive mechanism to adjust rates. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $26 million. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recorded smart meter revenues of $17 million reflecting recovery of our investments in this program. We also experienced higher other revenues of $2 million during the year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with seasonal threshold amounts. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP affecting the two-year period 2006 and 2007 is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	Residential	Non-Residential	First Tier	Second Tier
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2
November 1, 2007	1,000	750	5.0	5.9

Purchased power costs increased in 2007 by $19 million, or 1%, to $2,240 million compared to last year. Our increased purchased power costs were primarily due to higher demand for electricity of $57 million, higher wholesale commodity prices of $25 million for customers who are not eligible for the RPP and higher wholesale market service charges levied by the IESO of $7 million. These increases were partially offset by lower costs of $62 million associated with the OEB's RPP for residential and other eligible customers, combined with the impacts of the OEB's August 16, 2007 transmission rate decision of $8 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	2006	$ Change	% Change
Transmission	**415**	390	25	6
Distribution	**549**	460	89	19
Other	**31**	30	1	3
	995	880	115	13

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $25 million, or 6%, in 2007 compared to last year. Within our work programs, we continued our investments necessary for the safe and reliable operation of the transmission system. We experienced higher work program expenditures of $24 million primarily related to our planned station maintenance programs for power equipment and transformers and our line clearing and brush control programs, partially offset by lower requirements for unplanned corrective maintenance. We also experienced marginally higher expenditures in support of the transmission system. This increase reflects the commencement of a major business systems and processes project which will enable the adoption of more efficient, standardized business processes, the impact on our transmission regulatory accounts as a result of the OEB's August 16, 2007 transmission rate decision and the impact of a negotiated property tax settlement in 2006. The effect of these increases was partially offset by the impacts of a statutory reduction in our capital taxes and the reassignment of resources to support this year's larger transmission capital program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $89 million, or 19%, compared to last year. Increased requirements within our work program of $65 million primarily resulted from the planned expansion of our forestry and line maintenance programs incurred to increase reliability. In addition, we experienced increased customer participation in our conservation and demand management programs. These increases were partially offset by reductions in expenditures incurred to respond to storm damage. In addition, our costs increased due to impacts of last year's OEB rate decision, including the recognition of distribution-related pension costs which had been previously deferred as a regulatory asset. Our operating, maintenance and administration expenditures also increased as a result of the OEB's August 8, 2007 decision on its combined smart meter proceeding due to the recognition of smart meter-related operating expenditures that were incurred in the 2005 to 2007 period but which were previously deferred as regulatory assets. In addition to these increases, our other support expenditures were higher by $24 million as a result of resource requirements in support of the maintenance program and the commencement of a major business systems and processes project, partially offset by the impact of a statutory reduction in our capital taxes.

Depreciation and Amortization

Depreciation and amortization expense increased by $6 million, or 1%, to $521 million this year. This increase was mainly attributable to the placement of new assets in service, consistent with our ongoing capital work program. We also experienced higher amortization of our regulatory assets resulting from an April 12, 2006 OEB distribution rate decision that was effective on May 1, 2006. These increases were partially offset by lower fixed asset removal costs resulting from lower storm damage in the year, compared to 2006.

Financing Charges

Financing charges remain unchanged at $295 million compared to last year. We experienced a lower average effective interest rate on our outstanding debt which was offset by lower capitalized interest on our regulatory assets due to lower prescribed OEB rates and increased regulatory liabilities.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by $26 million, or 15%, to $205 million in 2007 compared to 2006. The increase is primarily due to last year's recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years, taxes payable on transmission amounts received this year but not recognized as revenue for accounting purposes, and temporary differences associated with certain regulatory accounts. These increases were partially offset this year by lower taxable income and other minor temporary differences.

Net Income

Net income of $399 million was lower by $56 million, or 12%, compared to 2006 results. Net income for the year was impacted by the OEB's August 16, 2007 transmission rate decision. While the OEB approved all of our work program requirements for 2007 and 2008, our return on equity was reduced from 9.88% to 8.35% effective January 1, 2007. Our net income also reflects higher requirements to operate and safely maintain our transmission and distribution systems, including enhanced transmission station maintenance and forestry programs. Our net income was further impacted by OEB decisions, including a 2006 decision affecting our distribution-related pension expenditures, last year's property tax settlement and a higher effective tax rate. These impacts were partially offset by an increase in our distribution revenues resulting from OEB-approved increases to our distribution tariff rates, as well as increased tariff revenue in our transmission and distribution businesses due to increased peak demands and energy consumption, as well as the elimination of last year's ESM.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2006 through December 31, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)				**2007**				2006
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues[1, 2]	**1,129**	**1,128**	**1,120**	**1,278**	1,142	1,165	1,078	1,160
Net income[1, 2]	**90**	**67**	**93**	**149**	101	103	99	152
Net income to common shareholder[1, 2]	**85**	**63**	**88**	**145**	96	99	94	148

1 The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

2 As a result of the OEB's August 16, 2007 decision on Hydro One Networks' transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Operating activities	**1,141**	909
Financing activities		
Long-term debt issued	**700**	775
Long-term debt retired	**(355)**	(589)
Short-term notes payable	**(60)**	60
Dividends paid	**(325)**	(350)
Investing activities		
Capital expenditures	**(1,091)**	(823)
Other financing and investing activities	**7**	(2)
Net change in cash and cash equivalents	**17**	(20)

Operating Activities

Net cash from operating activities increased by $232 million to $1,141 million, compared to 2006 results. Our working capital requirements were substantially lower than the comparative period primarily as a result of the impact of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005. Our working capital requirements were also impacted by lower electricity prices charged to RPP customers in 2007, the impacts of last year's OEB distribution rate decision and increased accounts payable primarily associated with our capital expenditure program.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. At December 31, 2007, we had no short-term notes payable outstanding. The commercial paper program is supported by a committed revolving credit facility with a syndicate of banks. On January 28, 2008, we increased the facility from $750 million to $1,000 million. The maturity date remains unchanged at August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2007, we had $5,615 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2008 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $2,200 million is remaining and is currently available until July 2009.

Rating Agency	Rating: Short-term Debt	Long-term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2007, we issued $700 million in long-term debt under our Medium-Term Note Program and we repaid $355 million in maturing long-term debt. In comparison, during 2006 we issued $775 million in debt under our Medium-Term Note Program and we repaid $589 million in maturing long-term debt. In 2007, we decreased our short-term notes by $60 million compared to an increase of $60 million in 2006.

In 2007, we paid dividends to the Province in the amount of $325 million, consisting of $307 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $332 million and preferred dividends of $18 million. In 2007, cash dividends per common share were $3,070 compared to $3,320 per common share in 2006. Cash dividends per preferred share were $1.375 in each of 2007 and 2006.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

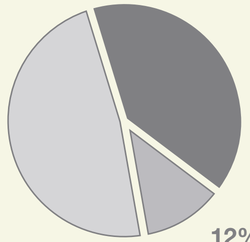
Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	2006	$ Change	% Change
Transmission	**560**	402	158	39
Distribution	**511**	417	94	23
Other	**20**	4	16	400
	1,091	823	268	33

Transmission

Transmission capital expenditures increased by $158 million in 2007 to $560 million, compared to 2006. Expenditures to expand and reinforce the transmission system were $271 million, representing an increase of $92 million over last year. This increase primarily reflects expenditures on our major lines and stations development projects. These projects include our new interconnection with Quebec, which will increase access to emission-free hydroelectric power, our Essa to Stayner connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers, and the completion of our Downtown Toronto Cable Project. Expenditures on our load and generation connections work have also increased primarily as a result of reconfiguration work at our Lambton Transformer Station and work at our London Talbot, Pleasant, and Holland transformer stations. The impact of these project expenditures was partially offset by last year's expenditure on our Niagara Reinforcement Project. This connection was substantially completed last year but final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the involved aboriginal peoples and the various government entities involved. We will complete this project when site access becomes available.

2007 Transmission Capital Expenditures

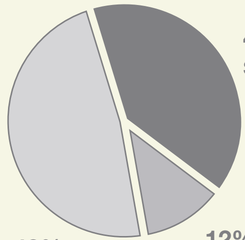


Expenditures to sustain our existing transmission system were $221 million, representing an increase of $31 million compared to 2006. This increase was primarily related to the refurbishment and replacement of end-of-life lines and stations, including work at our Claireville Transformer Station to improve current reliability and to meet growing demands, and protection and control work at our switchyard facility adjoining the Pickering Nuclear Generating Station. Our other transmission capital expenditures were $68 million in 2007, representing an increase of $35 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

Distribution

Distribution capital expenditures increased by $94 million to $511 million in 2007, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $245 million, an increase of $78 million compared to last year. This increase primarily reflects our ongoing investment in smart meters. During the year we installed approximately 260,000 meters, exceeding our 2007 target of approximately 240,000 meters, and bringing our cumulative program total to about 288,000 meters. We also experienced increased expenditures for new customer connections and for planned lines work, partially offset by slightly lower expenditures related to station meters.

2007 Distribution Capital Expenditures



Expenditures to sustain our low-voltage distribution system were $204 million, a reduction of $21 million from 2006. This reduction was primarily a result of lower storm-related expenditures. In 2007, we experienced lower capital expenditures of about $39 million to replace assets and components damaged or destroyed by major storms. Last year an unusual number of violent storms swept through the province and, in particular, a series of severe storms was experienced last summer. This impact was partially offset by higher planned end-of-life replacements of lines assets. Our other distribution capital expenditures were $62 million in 2007, representing an increase of $37 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

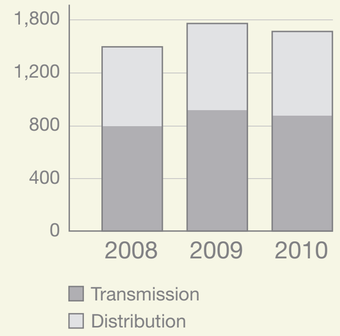
Other

Other capital expenditures made to enhance our telecom infrastructure increased by $16 million to $20 million in 2007. This increase was largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous health care locations in Ontario.

Future Capital Expenditures

Our capital expenditures in 2008 are budgeted at approximately $1.4 billion. The 2008 capital budgets for our transmission and distribution businesses are about $800 million and $600 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to exceed $1.5 billion in both 2009 and 2010, primarily reflecting increasing investments to expand, refurbish or replace transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with government policy, OPA planning information, local area supply requirements and the needs of preventive and corrective maintenance to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007. The replacement of critical information technology systems is also underway. Capital expenditures of our other business segment are budgeted at about $11 million in 2008, about half of the 2007 level, as the implementation of a dedicated fibre-optic network, initiated in 2007, will be completed in 2008.

Future Capital Expenditures
(Cdn $ millions)



Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2008 to 2010, amounting to about $2.5 billion. Our investment plan will address the needs of new generation development and load growth in local areas in the province. The transmission program also continues the focus on sustaining the performance of aging assets through maintenance and refurbishment programs and the replacement of assets that have reached their end of life.

With the primary focus of the recently filed IPSP being on mid- to long-term timeframes, the need justification for most major urgent, short-term transmission investments will continue through Leave-to-Construct (Section 92) proceedings. Referenced in the IPSP as short to mid-term investments is the project to connect redeveloped nuclear generation and wind from the Bruce Peninsula to our Milton Switching Station, other projects of local area supply, and the installation of equipment at our existing transmission stations. OEB and environmental approvals are being sought to build the 500kV line from the Bruce Peninsula, funding for which is included in the investment plan through to 2011. Given the timeframes required for stakeholdering, approvals, and construction, interim measures are being implemented to minimize the impact of generation scheduled to be available in 2009. These are comprised of the enhancement of the protection systems, the installation of Static Var Compensators and shunt capacitor banks in southwestern Ontario, and the upgrade of certain 230kV circuits.

Other projects included in the transmission investment plan include system expansions in northeastern Ontario to accommodate generation on the Mattagami River; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Windsor; and the interconnection between Ontario and Quebec. Construction of the Toronto third supply is contingent on the OEB approval of the IPSP and the OPA's determination of the need date. This project, for which funding is included in the plan, extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and as such, to maintain a reliable supply of electricity.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs, as partners in joint planning studies and throughout the consultation and approval processes, continue to be essential. Examples of projects under construction to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston, York Region and Red Lake. To address local future needs, we are in discussions with customers for major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Woodstock, Mississauga, Oshawa and Brampton. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems are expected to lead to improved reliability.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. Through targeted replacement programs for components, such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

The timing of many development projects is uncertain as they are dependent upon the final approval of the IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Capital expenditures for the period 2008 to 2010 are estimated to be approximately $2 billion, including the Smart Meter Program, and core development and sustainment programs. With approximately 1.3 million customers in our service territory, we anticipate installing about a further one million meters under the program. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. At the Province’s request, we will review our implementation plan and associated costs for the period from 2008 to 2010. Smart Network is an initiative that would leverage the smart meter infrastructure to enable functionality across our rural territory. This is currently being piloted and validated, and will be brought forward for consideration if benefits are confirmed.

Our core work will focus on demand programs such as new load connections, trouble calls and storm damage, and system capability reinforcement. The distribution investment plan also includes program expenditures relating to preserving the performance of our aging distribution asset base in order to improve system reliability. These include increased wood pole replacements, feeder sectionalization, and defect management, together with improved maintenance and line clearing practices. Given initiatives to encourage renewable energy technologies, we are experiencing increased distribution generation connection activity. Connection impact assessments are undertaken to determine project feasibility. Under OEB rules, the generator will pay connection costs other than distribution upgrades that also benefit other customers. No provision has been included in the plan for major distribution system modifications to accommodate this growth of new generation.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2007 (Canadian dollars in millions)	Total	2008	2009/2010	2011/2012	After 2012
Contractual obligations *(due by year)*:					
Long-term debt – principal repayments	5,615	540	800	850	3,425
Long-term debt – interest payments	5,211	307	554	488	3,862
Inergi LP (Inergi) outsourcing agreement[1]	396	100	190	106	–
Operating lease commitments	16	6	7	2	1
Total contractual obligations[5]	11,238	953	1,551	1,446	7,288
Other commercial commitments *(by year of expiry)*:					
Bank line[2]	750	–	750	–	–
Letters of credit[3]	99	99	–	–	–
Guarantees[3]	325	325	–	–	–
Pension[4]	196	94	102	–	–
Total other commercial commitments	1,370	518	852	–	–

1 On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

2 As a backstop to our commercial paper program, we have a $750 million revolving standby credit facility with a syndicate of banks which matures in August 2010. On January 28, 2008 this facility was increased to $1,000 million.

3 We currently have bank letters of credit of $95 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million. The maximum parental guarantee was increased in November 2007 to $325 million as a result of forecast power purchases and the November 1, 2007 change to our transmission rates. Although no letters of credit are currently required for prudential support, we would have to resume providing bank letters of credit if our highest long-term credit rating deteriorated to below the "Aa" category. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

4 Contributions to the pension fund are made one month in arrears. Contributions for 2008 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2008 and 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

5 In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these are considered individually material, and the majority will result in payments by our company by December 31, 2008.

The amounts in the above table under long-term debt – principal repayments, are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC.

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices, and our Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence our major business and corporate decisions. We have entered into a shareholder agreement with the Province relating to certain aspects of the governance of our company.

Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividend or payments in lieu of corporate income taxes. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us.

Risk Associated with Transmission Projects

Significant investments have been initiated to increase transmission capacity and enable the reliable delivery of power to Ontario consumers from existing and future generation sources. In many cases, initiating these investments is contingent upon one or more approvals. These can include Section 92, expropriation and environmental approvals, as well as consultation, and possibly accommodation with First Nations where traditional lands or lands subject to land claims are involved. The ability to make such investments may also be impacted by public opposition. If we are unable to make such investments, the reliability of our transmission system and our service quality could be adversely affected.

Workforce Demographic Risk

More than 20% of our employees will be eligible for retirement by the end of 2008. We expect the skilled labour market for our industry to be highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rate of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either or both of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2010. These expectations are factored into our revenue requirements for OEB approval. There is a risk that our revenues would be reduced if these targets are exceeded. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets under certain conditions.

As a transmitter, we expect to make significant investment in the coming years in large-scale transmission infrastructure projects and to connect new third-party load and generation assets. Additionally, there is always the possibility that we could incur unexpected capital expenditures to maintain or improve our assets. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we try to mitigate this risk by seeking from the regulator clear policy direction on cost responsibility and pre-approval of the need for capital expenditures.

The Province has passed regulations authorizing our subsidiaries, as distributors, to procure smart meters. Of the associated costs in rates, our subsidiaries Hydro One Networks and Hydro One Brampton are only currently authorized to recover 93 cents and 67 cents per metered customer per month, respectively. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment and charges to results of operations.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain the performance that is needed to support transmission reliability and service quality to our customers. Capital and maintenance programs have been increasing to maintain the performance of our aging asset base. However, execution of these plans is dependent on external factors including limited opportunities to remove equipment from service to accommodate construction due to outage constraints as determined by the IESO and substantially increased lead times for material and equipment due to increased global demand and limited vendor capability. Consequently, the necessary maintenance or replacements may be delayed, which could affect transmission reliability.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $900,000 per year that we currently are paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have a material adverse effect on our results of operations if we are unable to recover them in future rate orders.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. The existing collective agreements with the PWU will expire on March 31, 2008; collective bargaining commenced in January 2008. The Society of Energy Professionals' collective agreement was recently renewed and now expires on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face operational risk related to continued compliance with our license requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing our operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). These draft regulations may be finalized in 2008. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our Balance Sheet. If required, most of these additional expenditures would be incurred in the period from 2013 to 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our Balance Sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems to capture data and to produce timely and accurate information. We are working to transition most of our financial and business processes to an integrated business and financial reporting system which will enable productivity through the adoption of more efficient, standardized business processes. The conversion of these systems and processes may expose us to risk, including risks associated with maintaining internal controls, as new systems are brought online and the data and business processes are transitioned. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have a material adverse effect on our results of operations.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use provincially-owned transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The most recently filed valuation was prepared as at December 31, 2006 and was filed in September 2007. Our annual pension contributions for the three-year period 2007 to 2009 are approximately $94 million per year. The next valuation is required to be prepared as at December 31, 2009. The required level of contributions effective January 1, 2010 will depend on future investment returns, changes in benefits and changes in actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2008 and 2011. We are also planning a combined total of capital expenditures of approximately $3 billion in 2008 and 2009. Cash generated from operations will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Market and Credit Risk

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in the future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formula approach which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in determining our rate of return would reduce our transmission business' results of operations by approximately $20 million and our distribution business' results of operations by approximately $13 million. Our results of operations are adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% increase in interest rates on the refinancing of long-term debt maturing in 2008 and 2009 would reduce our results of operations by approximately $1 million and $4 million, respectively.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2007 amounted to $213 million and principally relate to regulatory asset recovery accounts (RARAs), employee future benefits other than pension, and environmental costs. We have also recorded regulatory liabilities amounting to $583 million as at December 31, 2007. These amounts pertain primarily to pension, the RDDA, export and wheeling fees, the ESM, and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. Most of our regulatory accounts have already been reviewed by the OEB and confirmed as recoverable or refundable.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. These future expenditures are discounted using factors ranging from 2.9% to 6.25%. Recording a liability for such long-term expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $94 million per year over the period 2007 through to 2009. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets was lower than this long-term assumption in 2007.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2007 increased by 0.25% from those at December 31, 2006 in conjunction with an increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $12 million per year and an increase in the year end obligation of about $167 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2007 and we determined that the carrying value of our goodwill has not been impaired.

Emerging Accounting Pronouncements

Transition to International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) ratified a new strategic plan for the period of 2006–2011 that entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over the five-year transitional period. The final AcSB decision to proceed on the intended schedule will be made in March 2008. It is generally expected that the decision to adopt IFRS will be confirmed unless some unexpected event occurs. The AcSB has adopted an implementation plan and suggests that companies be in a position to disclose their implementation plans for the IFRS changeover in their 2008 Management's Discussion and Analysis (MD&A). The Canadian Securities Administrators will be defining the MD&A disclosure requirements regarding an enterprise's plans for IFRS conversion. We started planning our transition to IFRS during 2006 and plan to commence convergence work beginning in 2008.

Accounting for Rate Regulated Operations

During 2007, the AcSB issued an exposure draft proposing to remove all specific references to rate regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes, and retain existing requirements to disclose the effects of rate regulation.

The new rules will apply prospectively to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2009 and will result in accrual accounting being followed for payments in lieu of corporate taxes. Such amounts are currently accounted for on a cash basis, consistent with specific OEB rate-setting direction. Commencing the first quarter of 2009, the regulatory impact of the OEB's direction will be reflected through the recognition of regulatory assets and/or liabilities. There will be no impact on results of operations.

Inventories

The AcSB issued new CICA Handbook Section 3031, *Inventories*, which is effective for our company in the first quarter of 2008. The recommendations apply to our materials and supplies inventories and require major spare parts to be classified as future use fixed assets rather than inventory. We anticipate a significant transfer of book value from the materials and supplies category on the Balance Sheet to fixed assets. Additionally, the new handbook section will allow the reversal of prior period write-downs when the net realizable value of impaired inventory subsequently recovers.

Disclosure Controls and Internal Controls over Financial Reporting

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. During 2005 and 2006, we documented all of our processes, risks and controls, and completed all testing necessary to make the required annual certifications. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that our disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis. Commencing with our Consolidated Financial Statements for the year ended December 31, 2006, we also made certifications regarding the design of our internal controls over financial reporting.

Our focus for 2007 has been the ongoing sustainment of our control environment, including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers). We have also carried out a comprehensive plan to test the operational effectiveness of our internal controls over financial reporting.

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2007, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and that they operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Selected Annual Information

The following table sets forth audited annual information for each of the three years ended December 31, 2005, 2006 and 2007. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statement of Operations

Year ended December 31 *(Canadian dollars in millions, except earnings per common share)*	**2007**	2006	2005
Revenues[1]	**4,655**	4,545	4,416
Net income[1]	**399**	455	483
Basic and fully diluted earnings per common share *(Canadian dollars)*	**3,809**	4,366	4,652

Consolidated Balance Sheet

Year ended December 31 *(Canadian dollars in millions, except cash dividends per share)*	**2007**	2006	2005
Total assets[2]	**12,790**	12,210	11,798
Total long-term debt[3]	**5,603**	5,243	5,032
Cash dividends per common share *(Canadian dollars)*	**3,070**	3,320	2,730
Cash dividends per preferred share *(Canadian dollars)*	**1.375**	1.375	1.375

1 As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

2 Total assets for 2006 and 2005 reflect the reclassification of deferred debt costs in 2007, applied retroactively.

3 Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Outlook

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our strategic priorities relating to respect of the public trust, safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our customer satisfaction and safety targets, while we maintain our financial profile and reliability performance. Our continued commitment to the people of Ontario has been recognized by the Edison Electric Institute (EEI) and by *Corporate Knights* magazine. Early in the year, EEI honoured us with the "Emergency Recovery Award" for outstanding storm restoration efforts in 2006. This was the first time a non-U.S. utility has won this prestigious award. *Corporate Knights* magazine recognized us as one of Canada's top 50 corporate citizens based on environmental, social and governance indicators. Our CDM program and leadership in the smart metering initiative were cited as key factors contributing to our ranking of third among utilities. This magazine also recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada, based on the composition of our Board, senior executives and the company's practices and policies on diversity. In addition, Hydro One was selected as the recipient of the Utility Planning Network's 2007 Metering Award in the category of Automated Meter Reading Initiative – North American Municipal or Cooperative among numerous entries from around the globe.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability. Our transmission investment plan supports the achievement of the Province's renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs, and facilitates the integration of new supply.

In its transmission rate decision issued on August 16, 2007, the OEB approved our entire operation, maintenance and administration and capital work programs applied for in 2007 and 2008, expressing confidence in our ability and expertise to make an appropriate assessment of what is needed "to maintain a robust, safe, and reliable transmission system." However, the decision was not favourable in other areas such as the approved return on equity. We plan to file a transmission rate application for 2009 and 2010 rates. These rates, if approved, should provide the funding required to maintain and meet the infrastructure requirements of the transmission system in the public interest.

Our investment plan does not include spending for large-scale investments, such as the east-west transmission grid or potential long-term transmission projects identified in the IPSP. For certain long-term projects addressing generation-enabling connection lines and reliability of local area supply, the IPSP recommends that project development work (preliminary engineering, cost estimating, options assessment, and Environmental Assessment and Section 92 approvals, as required) begin upon approval of the IPSP by the OEB. As such, we would be prepared to initiate project development work for these projects to enable expedited construction once a need date is confirmed by the OPA and once we have a reasonable expectation of cost recovery through rates. For some projects such as the transmission connection for generation in the Nipigon area, the IPSP recommends that development work commence in 2008. It is anticipated that the final decision to proceed with the longer term major projects, such as new high voltage transmission lines from north to south, will be made when the next IPSP is prepared in about three years.

The 2006 distribution rate decision has provided a base funding level to build upon. The 2008 Cost of Service application supports the implementation of our Smart Meter Program, and enhances sustainment programs to improve reliability and customer service. In 2007, an OEB decision clarified the recoverability of costs associated with the minimum level of smart meter functionality, thereby reducing the uncertainty of recovery of this program. Smart meter costs in excess of minimum functionality will be reviewed as part of the 2008 Cost of Service hearing. Given the magnitude and unique nature of the Smart Meter Program, recovery of costs will be a key focus. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2006, the government announced a two-year exemption of the electricity transfer tax. We will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis, where they are consistent with our strategy and direction from our shareholder. The investment plan does not include any funding for any LDC acquisitions or divestitures.

Key enablers of the successful implementation of the work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through partnering with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near-term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, sourcing strategies are being developed and implemented to ensure availability of materials to support the work programs.

Through the outlook period, we anticipate no changes to our role within the industry and that our financial returns will be sufficient to maintain our credit quality. In November 2007 the Agency Review Panel issued the second phase of its report on Ontario’s provincially-owned electricity agencies. The report confirmed that, overall, Ontario’s electricity sector and the provincial agencies within it are functioning reasonably well. We do not anticipate any structural changes to our company.

Forward Looking Statements and Information

Our oral and written public communications, including this MD&A, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to, statements about our strategy; statements related to the IPSP and projects flowing therefrom; statements about smart meters including costs, cost recovery and deployment and/or implementation plans; expectations regarding the timing, content and impact of future applications and decisions related to our transmission and distribution businesses; the anticipated results on our business processes and productivity as a result of our business systems and processes project; the anticipated impact of CDM programs; statements regarding the reliability of our distribution and transmission systems; expectations regarding load growth and new generation; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures and revenue requirements in both our transmission and distribution businesses and the timing of decisions from the OEB; statements regarding future capital expenditures and our investment plans; expectations regarding the results of our ongoing and planned projects; expectations regarding our strategy for acquisitions or divestitures of distribution assets; expectations regarding future pension contributions; expectations regarding workforce demographics; expectations regarding environmental expenditures and other environmental matters including the need for environmental approvals and assessments; expectations regarding borrowing requirements; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements regarding provincial ownership of our transmission corridors; the estimated impact of changes in the forecast long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; the estimated impact of changes in interest rates on our results of operations; statements about employee future benefit costs; statements about emerging accounting pronouncements; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, and structural changes to our company. Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario’s electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including potential conflicts of interest that may arise between us, the Province and related parties;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the potential impact of CDM programs on our load and our revenues;
- the potential impact of not being able to recover all of our project costs associated with the installation of smart meters;
- unanticipated changes in electricity demand or in our costs;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the potential for substantial and currently undetermined environmental costs and liabilities;
- the risks associated with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated;
- the impact of the ownership by the Province of lands underlying our transmission system;
- the potential impact of not being able to recover our pension costs;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks of counter-party default on our outstanding derivative contracts;
- the risks associated with changes in interest rates; and
- the risks associated with changes in the forecast long-term Government of Canada bond yield.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under “Risk Management and Risk Factors” in this MD&A, which you should review in detail.

This MD&A is dated as at February 13, 2008. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 13, 2008.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with Multilateral Instrument 52-109 (Bill 198). An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Auditors' Report, which appears on page 48, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures, and the design of related internal controls over financial reporting pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer

Beth Summers
Executive Vice-President and
Chief Financial Officer

Auditors' Report

To the Shareholder of Hydro One Inc.
We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2007 and December 31, 2006, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Licensed Public Accountants
Toronto, Canada
February 13, 2008

Consolidated Statements of Operations

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Revenues		
Transmission (Notes 7 and 13)	**1,242**	1,245
Distribution (Note 13)	**3,382**	3,273
Other	**31**	27
	4,655	4,545
Costs		
Purchased power (Note 13)	**2,240**	2,221
Operation, maintenance and administration (Note 13)	**995**	880
Depreciation and amortization (Note 3)	**521**	515
	3,756	3,616
Income before financing charges and provision for payments in lieu of corporate income taxes	**899**	929
Financing charges (Note 4)	**295**	295
Income before provision for payments in lieu of corporate income taxes	**604**	634
Provision for payments in lieu of corporate income taxes (Notes 5 and 13)	**205**	179
Net income	**399**	455
Other comprehensive income	**3**	–
Comprehensive income	**402**	455
Basic and fully diluted earnings per common share *(Canadian dollars)* (Note 12)	**3,809**	4,366

Consolidated Statements of Retained Earnings

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Retained earnings, January 1	**1,184**	1,079
Net income	**399**	455
Dividends (Note 12)	**(325)**	(350)
Retained earnings, December 31	**1,258**	1,184

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

December 31 *(Canadian dollars in millions)*	**2007**	2006
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts – $21 million; 2006 – $19 million) (Note 13)	**759**	777
Regulatory assets (Note 7)	**103**	121
Materials and supplies	**67**	56
Other	**17**	13
	946	967
Fixed assets (Note 6):		
Fixed assets in service	**16,812**	16,238
Less: accumulated depreciation	**6,220**	6,180
	10,592	10,058
Construction in progress	**622**	468
	11,214	10,526
Other long-term assets:		
Deferred pension asset (Note 10)	**380**	382
Regulatory assets (Note 7)	**110**	190
Goodwill	**133**	133
Other assets	**7**	12
	630	717
Total assets	**12,790**	12,210

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31 *(Canadian dollars in millions)*	**2007**	2006
Liabilities		
Current liabilities:		
Bank indebtedness	**12**	29
Accounts payable and accrued charges (Notes 11 and 13)	**731**	661
Regulatory liabilities (Note 7)	**114**	–
Accrued interest	**55**	49
Short-term notes payable (Note 8)	**–**	60
Long-term debt payable within one year (Note 8)	**540**	395
	1,452	1,194
Long-term debt (Note 8)	**5,063**	4,848
Other long-term liabilities:		
Employee future benefits other than pension (Note 10)	**855**	803
Regulatory liabilities (Note 7)	**469**	473
Environmental liabilities (Note 11)	**52**	55
Long-term accounts payable and accrued charges	**13**	16
	1,389	1,347
Total liabilities	**7,904**	7,389
Contingencies and commitments (Notes 9, 15 and 16)		
Shareholder's equity (Note 12)		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**1,258**	1,184
Accumulated other comprehensive income	**(9)**	–
Total shareholder's equity	**4,886**	4,821
Total liabilities and shareholder's equity	**12,790**	12,210

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Rita Burak
Chair

Walter Murray
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 *(Canadian dollars in millions)*	2007	2006
Operating activities		
Net income	**399**	455
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	**482**	474
Revenue difference deferral account	**73**	–
Retail settlement variance accounts	**46**	7
Other regulatory asset and liability accounts	**1**	19
Transmission earnings sharing mechanism	**–**	33
Amortization of debt discount	**5**	27
	1,006	1,015
Changes in non-cash balances related to operations (Note 14)	**135**	(106)
Net cash from operating activities	**1,141**	909
Financing activities		
Long-term debt issued	**700**	775
Long-term debt retired	**(355)**	(589)
Short-term notes payable	**(60)**	60
Dividends paid	**(325)**	(350)
Other	**(1)**	(4)
Net cash used in financing activities	**(41)**	(108)
Investing activities		
Capital expenditures	**(1,091)**	(823)
Other assets	**8**	2
Net cash used in investing activities	**(1,083)**	(821)
Net change in cash and cash equivalents	**17**	(20)
Cash and cash equivalents, January 1	**(29)**	(9)
Cash and cash equivalents, December 31 (Note 14)	**(12)**	(29)

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1.
Description of the Business

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Note 2.
Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc., Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc. and Hydro One Network Services Inc.

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services Inc. was dissolved on December 14, 2006. Hydro One Delivery Services Inc. will be dissolved pursuant to the *Business Corporations Act* (Ontario).

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. In October 2005, the OEB initiated a proceeding to review Hydro One Network's transmission rates and to approve revenue requirements for 2006, 2007 and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism (ESM) to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period ending January 1, 2006 until new transmission rates were set.

In September 2006, Hydro One Networks filed a transmission rate application. On March 30, 2007, prior to its decision on our transmission rate application, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, approved all operating and capital expenditures for 2007 and 2008. However, the decision resulted in a reduction in the approved return on equity from 9.88% to 8.35%. The OEB also approved final amounts and disposition treatments for certain regulatory liabilities including the RDDA, the ESM and export and wheeling fees, as well as the transmission market ready regulatory asset.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate applications in respect of the distribution businesses of Hydro One Networks and Hydro One Brampton. On the basis of the written evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

In 2006, the OEB commenced a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Hydro One Networks and Hydro One Brampton applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved the Company's submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a return of 8.64% for 2008. On December 18, 2007, Hydro One Networks filed the details of its cost allocation and rate design proposals, which include a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the Fall of 2008. On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 7.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2007 amounted to $413 million (2006 – $386 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). 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 Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission
Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution
Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication
Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service
Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements
Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2007 – 5.20%; 2006 – 6.39%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which are depreciated on a declining balance basis.

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the OEB. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation Rates (%)	
	Range	Average
Transmission	1%–4%	2%
Distribution	1%–13%	2%
Communication	1%–13%	5%
Administration and service	1%–20%	8%

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Financial Instruments

Effective January 1, 2007, the Company adopted four new accounting standards comprising the following sections of the Handbook of the Canadian Institute of Chartered Accountants (CICA): 1530, *Comprehensive Income*; *3855, Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation*; and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that were recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative annual Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges, and the change in fair value on existing cash flow hedges. The impact of the amortization of net hedging losses that were discontinued prior to the transition date was immaterial to the Statement of Operations.

Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with extendable maturity dates up to 2011 (see Notes 8 and 9).

Where there is an economic hedge, as in the case of the MTN Series 8 Note and associated interest rate swap, the Company has applied the fair value option without hedge accounting. The impact was not material.

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the Consolidated Balance Sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to AOCI. The hedging losses are amortized to financing charges using the effective interest method over the term of the hedged debt.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization basis from an annuity method to the effective interest method was not material.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Note 3.
Depreciation and Amortization

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Depreciation of fixed assets in service	**384**	379
Fixed asset removal costs	**39**	41
Amortization of regulatory and other assets	**98**	95
	521	515

Note 4.
Financing Charges

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Interest on short-term notes payable	**4**	2
Interest on long-term debt payable	**308**	296
Amortization of debt discount	**5**	27
Other	**7**	9
Less:		
Interest capitalized on construction in progress	**(24)**	(28)
Interest accreted on regulatory accounts	**–**	(7)
Interest earned on investments	**(5)**	(4)
	295	295

Note 5.
Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Income before provision for PILs	**604**	634
Federal and Ontario statutory income tax rate	**36.12%**	36.12%
Provision for PILs at statutory rate	**218**	229
Increase (decrease) resulting from:		
Net temporary differences:		
Transmission amounts received but not recognized for accounting purposes	**25**	12
Retail settlement variance accounts	**17**	2
Pension contributions in excess of pension expense	**(13)**	(16)
Overheads capitalized for accounting but deducted for tax purposes	**(12)**	(11)
Interest capitalized for accounting purposes but deducted for tax purposes	**(9)**	(13)
Capital cost allowance in excess of depreciation and amortization	**(9)**	(3)
Employee future benefits other than pension expense in excess of cash payments	**7**	14
Environmental expenditures	**(4)**	(6)
Recovery of PILs related to prior years	**–**	(30)
Other	**(5)**	2
Net temporary differences	**(3)**	(49)
Net permanent differences	**(10)**	(1)
Provision for PILs	**205**	179
Effective income tax rate	**33.94%**	28.23%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax liabilities of $253 million (2006 – $281 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company’s provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been lower by approximately $28 million (2006 – higher by $16 million), including the impact of a change in substantively enacted tax rates.

Future income taxes relating to the non-regulated businesses have also not been recorded in the accounts as they have not met the criterion of “more likely than not” to be realized. As at December 31, 2007, future income tax assets of $4 million (2006 – $4 million), based on substantively enacted income tax rates, have not been recorded.

Note 6.
Fixed Assets

December 31 *(Canadian dollars in millions)*	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2007				
Transmission	**8,708**	**3,152**	**370**	**5,926**
Distribution	**5,902**	**2,133**	**115**	**3,884**
Communication	**739**	**305**	**58**	**492**
Administration and service	**978**	**556**	**79**	**501**
Easements	**485**	**74**	**–**	**411**
	16,812	**6,220**	**622**	**11,214**
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	–	422
	16,238	6,180	468	10,526

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $24 million in 2007 (2006 – $28 million).

Note 7.
Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(Canadian dollars in millions)*	**2007**	2006
Regulatory assets:		
Regulatory asset recovery account II	**66**	87
Environmental	**65**	70
Employee future benefits other than pension	**42**	84
Regulatory asset recovery account I	**19**	58
Market ready	**13**	–
Smart meters	**4**	10
Other	**4**	2
Total regulatory assets	**213**	311
Less: current portion	**103**	121
	110	190
Regulatory liabilities:		
Deferred pension	**380**	382
Revenue difference deferral account	**73**	–
Retail settlement variance accounts	**50**	2
Export and wheeling fees	**38**	49
Transmission earnings sharing mechanism	**28**	34
Other	**14**	6
Total regulatory liabilities	**583**	473
Less: current portion	**114**	–
	469	473

Regulatory Assets

Regulatory Asset Recovery Account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $23 million (2006 – $16 million). In addition, related financing charges would have been higher by $3 million (2006 – $5 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $12 million (2006 – $17 million).

Employee Future Benefits Other Than Pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of one year (2006 – two years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $42 million (2006 – $42 million).

Regulatory Asset Recovery Account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. Hydro One Networks has requested an extension of the period for the RARA I recovery until such time as new rates are implemented. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Any over- or under-recovery of the RARA I due to continuance of the rate rider will be tracked for disposition at a future date. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $20 million (2006 – $20 million). In addition, related financing charges would have been higher by $1 million (2006 – $3 million).

Market Ready

In September 2006, as part of its transmission rate application, Hydro One Networks applied for the recovery of various regulatory deferral accounts including the transmission market ready costs incurred in connection with market opening. The transmission related transition costs were incurred to meet IESO requirement associated with registration and authorization activities. On August 16, 2007, as a result of the oral and written evidence the OEB approved the recovery of substantially all of these costs. Consequently, the market ready regulatory asset was established and recovery is being factored into rates over the four-year period ending December 31, 2010. In the absence of rate regulated accounting, operation, maintenance and administration expense would have been higher by $16 million (2006 – $nil) and revenue would have been higher by $4 million (2006 – $nil).

Smart Meters

On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and a monthly customer charge of 27 cents and 28 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively, was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In April 2007, as part of its decision regarding the Company's 2007 distribution rate applications, the OEB increased the monthly customer charge effective May 1, 2007 to 93 cents and 67 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure incurred by Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets. Such expenditures are now classified as capital or are charged to results of operations consistent with the Company's standard accounting practices. Expenditures determined to be above the minimum functionality have been brought forward for review in Hydro One Networks' cost of service rate application filed in 2007.

The OEB decision also required that related revenues be based upon a calculated revenue requirement specific to smart meters. As a result, the carrying value of the smart meter regulatory asset account represents the difference between revenue recorded on this basis and actual recoveries received under existing rate adders. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been lower by $3 million (2006 – higher by $4 million) and revenues would have been lower by $2 million (2006 – higher by $2 million).

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, operating, maintenance and administration expense would have been higher by $1 million (2006 – $50 million).

Revenue Difference Deferral Account (RDDA)

On March 30, 2007, the OEB issued a decision approving the establishment of the RDDA to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year. The new deferral account was to represent the revenue differential between existing and future rates for the period commencing January 1, 2007. On August 16, 2007, in its decision on Hydro One Networks' 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the RDDA liability, which will be returned to customers over the 14-month period ending December 31, 2008.

Retail Settlement Variance Accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its RSVA since May 1, 2006 which was taken into consideration in the revenue requirement of Hydro One Networks as part of the 2008 distribution rate application filed with the OEB in December 2007.

Export and Wheeling Fees

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006. In August 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export wheeling fees. The export wheeling fees will be factored into rates over a four-year period ending December 31, 2010.

Transmission Earnings Sharing Mechanism (ESM)

On February 21, 2006, the OEB issued a decision that established an ESM to equally share, between the Company's shareholder and ratepayers, any transmission earnings in excess of the approved rate of return of 9.88%, for the period ending January 1, 2006 until new transmission rates were set. Consequently, 50% of the Company's excess earnings were deferred as a regulatory liability. On March 30, 2007, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The ESM was taken into consideration in setting the revenue requirement of Hydro One Networks for 2007 and 2008. On August 16, 2007, in its decision on Hydro One Networks 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the ESM which will be returned to customers over a 14-month period ending December 31, 2008.

Note 8.
Debt

December 31 *(Canadian dollars in millions)*	**2007**	2006
Short-term notes payable	**–**	60
Long-term debt:		
4.45% notes due 2007	**–**	282
4.55% notes due 2007	**–**	73
4.70% (2006 – 4.10%) notes due 2008[1]	**40**	40
4.00% notes due 2008	**500**	500
3.95% notes due 2009	**400**	400
7.15% debentures due 2010	**400**	400
6.40% notes due 2011	**250**	250
5.77% notes due 2012	**600**	600
4.64% notes due 2016	**450**	450
5.18% notes due 2017	**300**	–
7.35% debentures due 2030	**400**	400
6.93% notes due 2032	**500**	500
6.35% notes due 2034	**385**	385
5.36% notes due 2036	**600**	600
4.89% notes due 2037	**400**	–
6.59% notes due 2043	**315**	315
5.00% notes due 2046	**75**	75
	5,615	5,270
Less:		
Long-term debt payable within one year	**(540)**	(395)
Net unamortized premiums	**13**	9
Unamortized hedging losses[2]	**–**	(12)
Unamortized debt issuance costs	**(25)**	(24)
Long-term debt	**5,063**	4,848

[1] Step-up coupon from 4.10% to 6.40%, extendable to 2011.

[2] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Short-term debt represents promissory notes issued pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2007, the notes had a weighted-average interest rate of 5.7%.

Hydro One has a $750 million committed and unused revolving standby credit facility with a syndicate of banks maturing in August 2010. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company issues notes for long-term financing under the Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $2,200 million is remaining and is currently available until July 2009.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2007, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	540	4.1
2 years	400	4.0
3 years	400	7.2
4 years	250	6.4
5 years	600	5.8
	2,190	5.3
6–10 years	750	4.9
Over 10 years	2,675	6.2
	5,615	5.7

Note 9.
Fair Value of Financial Instruments and Risk Management

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 *(Canadian dollars in millions)*	**2007**		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	**5,615**	**6,005**	5,270	5,831

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the step-up note, which is marked to market.

Hydro One may enter into derivative agreements, such as forward starting pay fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In October 2007, upon issuance of debt under the Company's Medium-Term Note Program, Hydro One terminated two forward interest rate swap agreements having a total notional principal amount of $200 million, resulting in a net gain of $0.4 million. The net gain was recorded as other comprehensive income and is being amortized to financing charges over the term of the related debt. In late 2007, Hydro One entered into two new forward starting pay fixed interest rate swap agreements with a notional amount of $140 million.

As at December 31, 2007, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. In 2006, the interest rate swap was accounted for as a fair value hedge. In 2007, the interest rate swap was accounted for using the fair value option without hedge accounting. This agreement has a notional principal amount of $40 million and a fair value of $nil (2006 – $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2007 or in 2006.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2007, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

Note 10.
Employee Future Benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2007 and 2006 was as follows:

	% of Plan Assets	
December 31	**2007**	2006
Equity securities	**62.5**	64.6
Debt securities	**34.1**	32.0
Other	**3.4**	3.4
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $90 million and $92 million at December 31, 2007 and 2006, respectively.

The Company's pension plan provides benefits based on the highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario on September 20, 2007, effective for December 31, 2006, the Company contributed $95 million to its pension plan in respect of 2007 (2006 – $86 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2007, consisting of cash contributed by the Company to its funded pension plan and cash paid directly to beneficiaries for its unfunded other benefit plans, was $137 million in 2007 (2006 – $122 million).

Year ended December 31 *(Canadian dollars in millions)*	Pension		Employee Future Benefits Other Than Pension	
	2007	2006	**2007**	2006
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**5,411**	5,355	**1,100**	1,143
Current service cost	**105**	106	**23**	33
Interest cost	**282**	267	**57**	58
Benefits paid	**(264)**	(253)	**(42)**	(36)
Plan amendments	**–**	6	**–**	22
Net actuarial gain	**(457)**	(70)	**(44)**	(120)
Accrued benefit obligation, December 31	**5,077**	5,411	**1,094**	1,100
Change in plan assets				
Fair value of plan assets, January 1	**5,123**	4,713	**–**	–
Actual return on plan assets	**142**	571	**–**	–
Benefits paid	**(264)**	(253)	**–**	–
Employer's contributions[1]	**95**	86	**–**	–
Employees' contributions	**17**	17	**–**	–
Administrative expenses	**(13)**	(11)	**–**	–
Fair value of plan assets, December 31	**5,100**	5,123	**–**	–
Funded status				
Funded excess (unfunded benefit obligation)	**23**	(288)	**(1,094)**	(1,100)
Unamortized net actuarial losses	**336**	645	**178**	236
Unamortized past service costs	**21**	25	**21**	25
Deferred pension asset (accrued benefit liability)	**380**	382	**(895)**	(839)
Less: current portion	**–**	–	**40**	36
Deferred pension asset (long-term liability)	**380**	382	**(855)**	(803)

[1] In January 2008, the Company made a contribution of $8 million in respect of 2007 (2007 – $8 million in respect of 2006).

Year ended December 31 (Canadian dollars in millions)	Pension 2007	Pension 2006	Employee Future Benefits Other Than Pension 2007	Employee Future Benefits Other Than Pension 2006
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**88**	89	**23**	33
Interest cost	**282**	267	**57**	58
Actual return on plan asset net of expenses	**(129)**	(560)	**–**	–
Actuarial gain	**(457)**	(70)	**(44)**	(120)
Plan amendments	**–**	6	**–**	22
Other	**–**	(1)	**–**	(1)
Costs arising in the period	**(216)**	(269)	**36**	(8)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**(212)**	248	**–**	–
Actuarial loss (gain)	**522**	177	**59**	149
Plan amendments	**3**	(3)	**4**	(19)
Net periodic benefit cost[2]	**97**	153	**99**	122
Charged to results of operations[2]	**58**	42	**60**	75
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**167**	156
Service cost and interest cost	**–**	–	**12**	13
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**(132)**	(124)
Service cost and interest cost	**–**	–	**(9)**	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**6.75%**	6.75%	**–**	–
Weighted-average discount rate	**5.25%**	5.00%	**5.24%**	4.98%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.50%	**2.50%**	2.50%
Average remaining service life of employees *(years)*	**10**	10	**9**	10
Rate of increase in health care cost trend[3]	**–**	–	**4.40%**	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	**5.50%**	5.25%	**5.50%**	5.24%
Rate of compensation scale escalation (without merit)	**3.00%**	3.25%	**3.00%**	3.25%
Rate of cost of living increase	**2.25%**	2.50%	**2.25%**	2.50%
Rate of increase in health care cost trend[4]	**–**	–	**4.40%**	4.40%

[2] The Company follows the cash basis of accounting. During 2007, pension costs of $95 million (2006 – $86 million) were attributed to labour, of which $58 million (2006 – $42 million) was charged to operations, $37 million (2006 – $34 million) was capitalized as part of the cost of fixed assets, and $nil (2006 – $10 million) was attributed to regulatory asset.

[3] 8.69% in 2007 grading down to 4.40% per annum in and after 2018 (2006 – 7.87% in 2006 grading down to 4.40% per annum in and after 2014).

[4] 8.33% in 2008 grading down to 4.40% per annum in and after 2018 (2006 – 8.69% in 2007 grading down to 4.40% per annum in and after 2014).

Note 11.
Environmental Liabilities

December 31 *(Canadian dollars in millions)*	**2007**	2006
Environmental liabilities, January 1	**70**	79
Interest accretion	**4**	5
Expenditures	**(12)**	(17)
Revaluation adjustment	**3**	3
Environmental liabilities, December 31	**65**	70
Less: current portion	**(13)**	(15)
	52	55

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 – $13 million; 2009 – $12 million; 2010 – $10 million; 2011 – $8 million; 2012 – $6 million and thereafter – $35 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

Note 12.
Share Capital

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2007, preferred dividends in the amount of $18 million (2006 – $18 million) and common dividends in the amount of $307 million (2006 – $332 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

Note 13.
Related Party Transactions

The Province, OEFC, IESO, OPA and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2007 includes $1,203 million (2006 – $1,206 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2007 includes $127 million (2006 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2007 includes $21 million (2006 – $21 million) related to these services.

In 2007, Hydro One purchased power in the amount of $2,213 million (2006 – $2,183 million) from the IESO administered electricity market and $27 million (2006 – $38 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2007, Hydro One incurred $10 million (2006 – $9 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $12 million (2006 – $15 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2007 and 2006.

Consistent with the OPA mandate, the OPA is responsible for some of our CDM programs. The funding includes program costs, incentives and management fees and bonuses. In 2007, Hydro One received $3 million (2006 – $nil) from the OPA in respect of the CDM programs and had a net accounts receivable of $3 million (2006 – $nil).

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 *(Canadian dollars in millions)*	**2007**	2006
Accounts receivable	**97**	114
Accounts payable and accrued charges	**(234)**	(230)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $202 million (2006 – $195 million).

Note 14.
Consolidated Statements of Cash Flows

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Balance Sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Accounts receivable decrease (increase)	**18**	(149)
Materials and supplies increase	**(11)**	–
Accounts payable and accrued charges increase (decrease)	**70**	(39)
Accrued interest increase	**6**	6
Long-term accounts payable and accrued charges decrease	**(3)**	(7)
Employee future benefits other than pension increase	**52**	87
Other	**3**	(4)
	135	(106)
Supplementary information:		
Interest paid	**306**	302
Payments in lieu of corporate income taxes	**230**	252

Note 15.
Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the 20th century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the approximately $900,000 per year than it currently is paying to these Indian bands and bodies. If the Company cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if it is not able to recover them in future rate orders.

Draft PCB Regulations

Future changes in environmental regulations may result in material changes to the Company's estimated liability related to the management of PCBs. On November 4, 2006, Environment Canada published new draft regulations governing the management of PCBs. These draft regulations may be finalized in 2008. The Company has estimated its operating expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts already recorded as environmental liabilities on its Balance Sheet. If required, most of these additional expenditures are expected to be incurred between 2013 and 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In the event that an obligation related to new regulations is recorded, the Company expects to simultaneously record a regulatory asset of equivalent value.

Note 16.
Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2007, and in total thereafter are as follows: 2008 – $100 million; 2009 – $97 million; 2010 – $93 million; 2011 – $90 million; 2012 – $16 million and thereafter – $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2007, the Company provided prudential support using only parental guarantees, reflecting a change from 2006. If Hydro One's highest long-term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support. Prudential support at December 31, 2007 was provided using bank letters of credit of $nil million (2006 – $22 million) and parental guarantees of $325 million (2006 – $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2007, Hydro One had bank letters of credit of $95 million (2006 – $93 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 – $6 million; 2009 – $5 million; 2010 – $2 million; 2011 – $1 million; 2012 – $1 million and thereafter – $1 million.

Note 17.
Segment Reporting

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The “other” segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 *(Canadian dollars in millions)*	Transmission	Distribution	Other	Consolidated
2007				
Segment profit				
Revenues	**1,242**	**3,382**	**31**	**4,655**
Purchased power	**–**	**2,240**	**–**	**2,240**
Operation, maintenance and administration	**415**	**549**	**31**	**995**
Depreciation and amortization	**242**	**273**	**6**	**521**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**585**	**320**	**(6)**	**899**
Financing charges				**295**
Income before provision for payments in lieu of corporate income taxes				**604**
Capital expenditures	**560**	**511**	**20**	**1,091**
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	–	2,221	–	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823

December 31 *(Canadian dollars in millions)*	**2007**	2006
Total assets		
Transmission	**7,273**	6,950
Distribution	**5,411**	5,161
Other	**106**	99
	12,790	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

Note 18. Subsequent Events

On January 21, 2008, the Company entered into a forward starting pay fixed interest rate swap agreement to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $60 million and is used to lock in the interest rate of a forecasted debt issuance planned for later in 2008. This transaction is being accounted for as a cash flow hedge of a forecasted transaction.

On January 28, 2008 the Company increased its committed revolving credit facility, which supports its commercial paper program, by $250 million to $1,000 million. The maturity date remains unchanged at August 10, 2010.

Note 19. Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2007 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006	2005	2004	2003
Statement of operations data					
Revenues					
Transmission	**1,242**	1,245	1,310	1,262	1,298
Distribution	**3,382**	3,273	3,085	2,874	2,734
Other	**31**	27	21	17	26
	4,655	4,545	4,416	4,153	4,058
Costs					
Purchased power	**2,240**	2,221	2,131	1,987	1,872
Operation, maintenance and administration	**995**	880	792	771	795
Depreciation and amortization	**521**	515	487	480	454
	3,756	3,616	3,410	3,238	3,121
Regulatory recovery[1]	**–**	–	–	91	–
Income before financing charges and provision for payments in lieu of corporate income taxes	**899**	929	1,006	1,006	937
Financing charges	**295**	295	325	331	348
Income before provision for payments in lieu of corporate income taxes	**604**	634	681	675	589
Provision for payments in lieu of corporate income taxes	**205**	179	198	177	193
Net income	**399**	455	483	498	396
Basic and fully diluted earnings per common share *(Canadian dollars)*	**3,809**	4,366	4,652	4,798	3,779

Five-Year Summary of Financial and Operating Statistics (continued)

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006	2005	2004	2003
Balance sheet data					
Assets					
Transmission	**7,273**	6,950	6,813	6,771	6,576
Distribution	**5,411**	5,161	4,893	4,836	4,614
Other	**106**	99	92	95	94
Total assets	**12,790**	12,210	11,798	11,702	11,284
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,452**	1,194	1,341	1,262	1,192
Long-term debt	**5,063**	4,848	4,443	4,590	4,517
Other long-term liabilities	**1,389**	1,347	1,298	1,326	1,284
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,258**	1,184	1,079	887	654
Accumulated other comprehensive income	**(9)**	–	–	–	–
Total liabilities and shareholder's equity	**12,790**	12,210	11,798	11,702	11,284

Five-Year Summary of Financial and Operating Statistics (continued)

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006	2005	2004	2003
Other financial data					
Capital expenditures					
Transmission	**560**	402	349	432	289
Distribution	**511**	417	338	288	292
Other	**20**	4	4	7	16
Total capital expenditures	**1,091**	823	691	727	597
Ratios					
Net asset coverage on long-term debt[2]	**1.87**	1.92	1.93	1.88	1.86
Earnings coverage ratio[3]	**2.67**	2.67	2.69	2.70	2.43
Operating statistics					
Transmission					
Units transmitted *(TWh)*[4]	**152.2**	151.1	157.0	153.4	151.7
Ontario 20-minute system peak demand *(MW)*[4]	**25,809**	27,056	26,219	25,204	24,849
Ontario 60-minute system peak demand *(MW)*[4]	**25,737**	27,005	26,160	24,979	24,753
Total transmission lines *(circuit-kilometres)*	**28,915**	28,600	28,547	28,643	28,621
Distribution					
Units distributed to Hydro One customers *(TWh)*[4]	**30.2**	29.0	29.7	28.5	27.9
Units distributed through Hydro One lines *(TWh)*[4, 5]	**45.7**	44.7	45.6	44.8	44.7
Total distribution lines *(circuit-kilometres)*	**122,933**	122,460	122,118	121,736	121,285
Customers	**1,311,714**	1,293,396	1,273,768	1,258,925	1,238,748
Total regular employees	**4,602**	4,295	4,189	4,118	3,967

1 As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004, the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

2 The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

3 The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

4 System-related statistics include preliminary figures for December.

5 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Board of Directors (as at December 31, 2007)

Rita Burak[2*]
Chair of the Board of Directors, Hydro One Inc.

Sami Bébawi[5, 6]
Advisor to the President, SNC-Lavalin Group Inc.
President, Geracon Inc.

Kathryn A. Bouey[3, 4, 6]
President, Kathryn Bouey & Associates Ltd.
Corporate Director

Murray J. Elston[1, 5]
President and CEO, Canadian Nuclear Association

Laura Formusa
President and CEO, Hydro One Inc.

Don MacKinnon[5, 6]
President, Power Workers' Union

Michael J. Mueller[2, 4]
Corporate Director

Walter Murray[1, 3, 4]
Corporate Director

Robert L. Pace[1, 3]
President and CEO, The Pace Group Ltd.

Gale Rubenstein[1, 2, 5]
Partner, Goodmans LLP

Douglas E. Speers[3, 4, 6]
Chairman and Director, Emco Corporation

Board Committees

[1] **Audit and Finance Committee**
The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met six times in 2007.

[2] **Corporate Governance Committee**
The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2007.

[3] **Human Resources and Public Policy Committee**
The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on us. The committee met 11 times in 2007.

[4] **Business Transformation Committee (Formerly the Information Technology Committee)**
The Business Transformation Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met five times in 2007.

[5] **Regulatory and Environment Committee**
The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met six times in 2007.

[6] **Health and Safety Committee**
The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2007.

* Effective March 31, 2008, James Arnett was elected as Chair of the Board of Directors of Hydro One Inc. by our shareholder following the resignation of Rita Burak, who did not seek reappointment.

Corporate Information

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1-800-434-1235

Residential, farm &
small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
Ernst & Young LLP

Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
FSC
www.fsc.org Cert no. SW-COC-1383
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Concept and Design: **THE WORKS** **www.worksdesign.com** Principal Photography: **Lorne Bridgman**

Something To Smile About.

Hydro One customers have saved more than 272 million kWh of energy since our Conservation and Demand Management program was launched in 2005.

Our Conservation and Demand Management (CDM) initiatives have helped Hydro One customers substantially reduce their energy consumption. To date, they have saved an astonishing 272 million kWh of energy – that's enough electricity to power 23,000 homes for an entire year. This also reduces carbon emissions to the environment by 178,000 tonnes.

Our Conservation and Demand Management programs have had more than 1.1 million participants and that number continues to grow daily.

Over the five-year average life span of efficiency measures installed, the expected electrical savings are almost 1.5 billion kWh – that is equivalent to powering 120,000 homes for one year.

$3.40 in societal benefits

Every dollar we've spent on CDM is worth $3.40 of societal benefits, as measured through the Total Resource Cost test.

10,000 smart stats

We installed 10,000 web-enabled thermostats that allow central air conditioners to be remotely turned down during peak demand hours.

2,200 traffic signals

2,200 traffic signals in 16 municipalities were replaced with LED technologies, saving 1.7 million kWh annually.

31,000 monitors

We installed 31,000 real-time electricity use monitors in northern Ontario. Seeing real-time data on a daily basis can reduce electricity consumption by up to 15%.

11,000 recycled appliances

We picked up more than 11,000 old refrigerators, freezers and room air conditioners and disposed of them in an environmentally responsible manner.

www.HydroOne.com

483 Bay Street
Toronto, Ontario
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(416) 345-5000
1-877-955-1155

Hydro One Remote Communities Inc.
Reconciliation of Regulatory Financial Results with Audited Financial Statements
For year ending December 31, 2006

	Total per Exhibit A-9-1, Attachment 3 (a)	Adjustments (b)	Utility Income (c)
Revenue			
Retail power & energy	12,530		12,530
RRRP	24,723		24,723
Late Payment Charges	1,217		1,217
Other (Note 1)	50		50
	38,520	-	38,520
Costs			
OM&A	15,187	(136)	15,051
Cost of fuel	18,608		18,608
Depreciation	3,980		3,980
Taxes other than income tax (Note 1)		136	136
	37,775	-	37,775
Income before financing charges and provision for payments in lieu of corporate income taxes	745	-	745
Financing Charges	1,329		1,329
Income before provision for payments in lieu of corporate income taxes	(584)	-	(584)
Provision for Payments in lieu of corporate income taxes (Note 3)	(584)	(410)	(994)
Net Income	-	410	410

Note 1: Capital taxes are included in Remotes audited OM&A total, whereas in the rate evidence are shown as a separate line item. The evidence

Note 2: Difference relates to prior year tax reassessments or adjustments paid or made in 2006, such as the 1999-2001 CCA changes, 2005 provision to return filed, etc.

HYDRO ONE REMOTE COMMUNITIES INC.
2007 Financial Statements reconciled to USofA Trial balance

STATEMENT OF OPERATIONS (Year ended December 31, 2007)

	Financial Statement item	**USofA Account/s**	**$ millions**
	REVENUES		
34	Energy sales	4006, 4010, 4025	$ 12,653
35	Rural rate protection	4105	22,852
	Late Payment Charge	4225	1,037
36	Other Revenue	4325	130
37	TOTAL REVENUE		36,672
	COSTS		
38	Fuel used for electric generation	4510	19,319
	Operation, maintenance & administration		
39	Generation	4550, 4555, 4610, 4635	8,067
40	Distribution	5085, 5120, 5125, 5130, 5135, 5175	1,241
41	Customer Care	5310, 5315, 5320, 5335	1,874
42	Community Relations	5410, 5415, 5420	413
43	Administrative and Other Expenses	4330, 5615, 5625, 5655, 6105	1,041
44			
45	Depreciation and amortization	5705, 5715, 5740,	4,002
46	TOTAL COSTS		35,957
47	**Income before financing charges & provision for payments in lieu of corporate income taxes**		715
48	Financing charges	6005, 6010, 6035, 6040	1,142
49	**Income before provision for payments in lieu of corporate income taxes**		(427)
50	Provision for payments in lieu of corporate Income taxes	6110	(427)
51	**Net income**		**$ (0)**
	Other comprehensive income	4375	9
	Comprehensive income		$ 9

SUMMARY OF HYDRO ONE REMOTE COMMUNITIES POLICIES

1.0 INTRODUCTION

Hydro One has a number of corporate policies that apply to Remotes, its customers, assets and systems, and financial management. Policies are subject to periodic review and/or revision as a result of statutory or regulatory change, or as the business evolves. The objectives of these policies are to ensure:

- compliance with statutory and regulatory obligations;
- fair and consistent commercial relationships with customers;
- efficient management of assets;
- consistent criteria for decision making;
- compliance with generally-accepted accounting principles;
- consistency for transaction processing; and,
- accurate and timely recording and reporting of financial information.

2.0 CHANGES TO POLICIES

In keeping with good corporate governance, Hydro One has reviewed and revised the following corporate policies and procedures since the Board's review of Remotes' rates for 2006, RP-2005-0020/EB-2005-0497. These policies and procedures apply to all Hydro One subsidiaries, including Remotes.

- Procurement Policy
- Procurement Procedure
- Corporate Policy on Consultants
- Corporate Procedure for Retention of Consultants

- Corporate Charge Card Procedure
- Policy on Employee Business Expenses
- Employee Business Expenses Procedure

The following represent significant changes to the company's key policies since the RP-2005-0020/EB-2005-0378 Board review.

2.1 Comprehensive Income, Financial Instruments and Hedging

Effective January 1, 2007, Hydro One adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' ("CICA") Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income ("AOCI"). Comprehensive income is composed of the Company's net income and other comprehensive income ("OCI"). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date.

Under the new financial instruments standards, all financial instruments are classified into one of five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. Remotes' classification of existing financial instruments is summarized in the notes to its 2007 annual financial statements.

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. Where there is an economic hedge, Hydro One has selected to apply the fair value option without hedge accounting for all of its subsidiaries. All financial instrument transactions are recorded at trade date.

Upon adoption of the new standards, Hydro One reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to AOCI. The hedging losses are amortized through OCI over the term of the hedged debt. Previously these unamortized gains and losses were disclosed net with long-term debt.

Transaction costs for financial assets and liabilities that are classified as other than held-for-trading, are added to the carrying value of the asset or liability and amortized over the expected life of the instrument. Previously such costs incurred as a result of the issuance of long-term debt were disclosed as a separate long-term asset on the Balance Sheet.

2.2 Accounting for Conditional Asset Retirement Obligations

Effective April 1, 2006, Hydro One adopted new accounting recommendations for Conditional Asset Retirement Obligations issued by the Emerging Issues Committee of the CICA. Most of these obligations are not currently estimable because final retirement and removal dates cannot be determined as the related assets are expected to be used on an ongoing basis. Remotes determined that it had no such obligations.

2.3 Accounting for Inventories

Effective January 1, 2008, Hydro One adopted new accounting recommendations related to Inventories. The new accounting rules require that certain major spare parts and standby equipment be reclassified from inventory to fixed assets. Such reclassified assets will be disclosed in the annual financial statements under the caption "future use components and spares." The new rules also allow that previously recorded impairment losses taken on inventory to be reversed if there is evidence that the net realizable value has subsequently recovered.

Future use components and spares are not depreciated until they are transferred to active capital projects and those projects are placed in-service.

SUMMARY OF INITIATIVES BASED ON LEGISLATIVE CHANGES

1.0 INTRODUCTION

Remotes is subject to direction from its shareholder (the Government of Ontario), Ontario Energy Board decisions and federal and provincial government legislation and regulations. Each one of these sources has the potential to be a driver for change affecting Remotes' policies, processes and work programs, with associated cost implications. Remotes complies with all regulatory and legislative requirements and incurs costs to do so. When new legislation or regulations are passed, or when OEB decisions are released, Remotes responds to the directive by developing appropriate programs or initiatives to implement the required changes in a cost-effective fashion. The remainder of this Exhibit provides a brief summary of the key pieces of legislation, regulatory requirements, standards and guidelines to which Remotes must respond.

2.0 THE DISTRIBUTION SYSTEM CODE

Remotes is bound by the terms of its Distribution licence to adhere to the requirements of the Distribution System Code ("DSC"), administered by the Ontario Energy Board.

The DSC provides the minimum conditions a distributor must meet in carrying out its obligation to operate, maintain, manage and expand distribution systems and requires Remotes to operate and maintain its system in accordance with "good utility practice." The DSC sets out the obligations of electricity distributors with respect to their customers, including the rules governing the economic evaluation of distribution system connections and expansions and also the minimum standards for facilities connected to a distribution system. It also includes guidance on the form of the Connection Agreement for load customers, which covers the technical and commercial responsibilities for both Remotes and the customer.

3.0 ENVIRONMENTAL MANAGEMENT

Remotes is subject to a wide range of environmental legislation. The following are the major acts that govern its activities. Many others can apply in specific circumstances but the following are applicable to the majority of its work.

3.1 Federal Legislation

- *Canadian Environmental Protection Act*, which regulates the management of hazardous substances.
- *Fisheries Act*, which regulates fish habitat and pollution prevention in and around water bodies that support fish.
- *Canadian Environmental Assessment Act* – The Act requires federal departments, including Environment Canada, agencies and crown corporations to conduct environmental assessments for proposed projects where the federal government is the proponent. It also requires environmental assessments when the project involves federal funding, permits or licences.

3.2 Provincial Legislation

- *Environmental Protection Act*, which regulates waste management/disposal, spills and Certificates of Approval.
- *Ontario Water Resources Act*, which regulates discharges, sewage works and water works.
- *Pesticides Act*, which regulates the storage, use and application of pesticides.

- *Environmental Assessment Act*, which regulates the planning and environmental approvals of projects.
- *The Technical Standards and Safety Act*, which governs fuel storage and handling.

3.3 Environmental Programs

The following is a summary of the major programs, which are discussed in Exhibit C1, Tab 2.

3.3.1 Fuel Management

Remotes handles 14 to 17 million litres of fuel each year. Fuel is handled in accordance with rules and standards set out by the Technical Standards and Safety Authority (TSSA). The TSSA also establishes operation and maintenance standards for fuel management, handling and transfer. Remotes' fuel storage and auxiliary systems are designed and operated in accordance with these standards, and the TSSA regularly inspects Remotes' fuel systems. Remotes also has several ongoing activities related to fuel management, handling and transfer.

3.3.2 Land Assessment and Remediation ("LAR")

LAR is discussed in more detail in Exhibit C1, Tab 2, Schedule 2, Appendix A

3.3.3 Hazardous Materials and Waste

Management and Transportation of hazardous materials and wastes such as oils and solvents are managed in accordance with regulatory requirements and good management practices. Remotes' generating facilities have secure outbuildings to safely store waste materials. Hazardous waste is transported out of communities over winter roads in accordance with various reporting requirements under the *Environmental Protection Act* and *Waste Management Regulation 347*.

Hazardous materials such as wastes (oils, solvents, etc.) are managed in accordance with regulatory requirements and good management practices.

3.3.4 Greenhouse Gas Emissions Reductions

The regulation of industrial greenhouse gas emissions by governments seems likely. Remotes has a strategy in place to reduce these emissions. Remotes subscribes to the Canadian Greenhouse Gas Challenge Registry, Canadian Standards Association Climate Change Office's Voluntary Challenge Program and won the Gold Champion Award for best new submission in 2003. Remotes submits annual emission reduction action plans and documents its progress. In 2007, emission reduction activities brought savings of 13,302.51 tonnes of CO2e (tonnes CO2e/kWh produced) from both direct and indirect sources.

4.0 ELECTRICAL SAFETY AUTHORITY

The Electrical Distribution Safety Regulation 22/04 established objective-based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. It requires:

- Approval of equipment, designs and plans.
- Inspection and certification of construction before it is put into use.
- An assessment of plant based on the Ontario Electrical Safety Code prior to selling plant to non-distributors.

- Approval by the utility to place objects at a distance less than CSA clearance standards from distribution lines.
- Disconnection of unused lines.
- Reporting of serious electrical incidents.
- Annual compliance audits of processes.
- Safety due diligence inspections conducted by the ESA to ensure safety standards are met.

Electrical safety is a very high priority for Remotes as indicated in the strategic goals in Exhibit A, Tab 3, Schedule 1. To address this priority Remotes has implemented comprehensive training programs to ensure all Electrical Safety Regulations are adhered to across the business.

5.0 SMART METERS

The enactment of the *Energy Conservation Leadership Act*, and changes to the *Electricity Act* and the *Ontario Energy Board Act*, along with new regulations, have defined the Government's Smart Meter Initiative, and prescribed the technical and functional requirements of the smart meter solutions (Advanced Metering Infrastructure – AMI).

In line with the legislative and regulatory requirements, Remotes is planning to begin deploying smart meter technology in 2009 after other distribution companies have deployed smart meters to rural communities. Remotes feels it can benefit from lessons learned about deployment in areas of the province that may lack communications infrastructure. Investments related to smart meters are discussed in Exhibit D1, Tab 2, Schedule 1.

6.0 CONSERVATION AND DEMAND MANAGEMENT

Remotes' CDM initiative is described in more detail in Exhibit C1, Tab 2, Schedule 5.

7.0 BILL 198 – INTERNAL CONTROLS

Bill 198 requires that the controls that oversee the processes and systems that impact how the company initiates, records, processes, and reports transactions in significant accounts must be documented and evaluated on an annual basis. The Ontario Securities Commission (OSC) responded to Bill 198 with new Multilateral Instruments (MI) that govern internal controls. These require the CEO and CFO of Hydro One Inc. (as a public debt issuer) to attest to the appropriateness and effectiveness of internal financial controls and financial disclosure processes for the Company's consolidated financial information.

By the end of 2006, Hydro One completed its project to ensure compliance with Bill 198 requirements in all of its subsidiaries, including Remotes. This entailed changes to processes and technologies to ensure appropriate documentation is in place for the first year of compliance (2007). In addition, a unit has been put in place to sustain the Bill 198 requirement on an on-going basis. Hydro One is currently performing its 2008 compliance testing.

8.0 ACCESS TO INFORMATION (FIPPA) AND PERSONAL PRIVACY (PIPEDA)

On December 10, 2003, Hydro One Inc. became subject to Ontario's Freedom of Information and Protection of Privacy (FIPPA) legislation. On January 1, 2004, Hydro One Inc. also became subject to Canada's Protection of Individual Privacy and Electronic Documents Act (PIPEDA). And most recently, on November 1, 2004, the Corporation also became subject to Ontario's Personal Health Information Protection Act.

These pieces of legislation require that the Corporation provide public access to business records, as well as appropriate access to (and protection of) personal information. The personal information of customers and, in specific circumstances, employees, is now subject to legislated standards of protection.

PLANNING PROCESS

1.0 INTRODUCTION

Business planning is performed annually and focuses on the development of a five-year plan which comprises a detailed plan for the first three years in the planning cycle and a less detailed outlook for the remaining two year period. The planning cycle in 2008 pertained to the 2009-2013 period. The results as they apply to 2009 (the test year) form the basis for this rate submission.

The annual planning cycle consists of five phases:

1. Confirmation of corporate strategy;
2. Development of economic outlook and forecast assumptions;
3. Investment plan development;
4. Development of plans and work programs; and,
5. Refinement of plan into a detailed budget.

The key dates applicable to the 2009-2013 planning cycle include:

Date	Action
December 2007	Strategic goals confirmed
February 2008	Risk Review
March 2008	Business plan instructions issued
April 2008	Business plan submitted to Remotes' President & CEO for approval
May 2008	Lines of business submit business plans to Hydro One Executive Committee

May 2008	Hydro One Executive Committee holds business plan review meetings with lines of business vice presidents
August 2008	Hydro One Inc. Board approval of business plan
November 2008	Hydro One Inc. Board approval of detailed budget

2.0 STRATEGIC DIRECTION AND GOALS ESTABLISHED BY SENIOR MANAGEMENT

Remotes' strategic direction and goals are reviewed and confirmed by the CEO and other members of the senior management team. The strategic goals are included in the business planning instructions for reference by planners as the business plan is being developed. Please see Exhibit A, Tab 3, Schedule 1 for a description of the Company's strategic goals.

3.0 DEVELOPMENT OF ECONOMIC OUTLOOK AND PLANNING ASSUMPTIONS

To facilitate the preparation of the business plan, an economic outlook and customer load forecast is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, cost allocation percentages, and cost rates for benefits. The assumptions used for the 2009 business plan are attached to this exhibit as Appendix A. A detailed discussion of the economic indicators is filed at Exhibit A, Tab 13, Schedule 2.

4.0 BUSINESS PLANNING

Annually, Remotes reviews risks related to its operations and the required investments to achieve its strategic goals. Customer needs, operational performance and asset condition are examined to identify areas where work is required. This results in a business plan that is then submitted to Remotes' President and CEO for review and approval. The business plan prepared during 2008 provides the basis for the 2009 forecast.

5.0 DEVELOPMENT OF PLANS AND WORK PROGRAMS

During the planning process, plans and work programs are further refined consistent with the economic and forecast assumptions. As part of this process, sufficient detail is provided to facilitate preparation of the 2009 Rate Application. At the end of this process, the senior management team provides direction as necessary in order to balance the various factors under consideration including customer service levels, rate impacts and RRRP.

The operations, maintenance and administration ("OM&A") budget and the capital budget that result from this planning process are discussed at Exhibit C1, Tab 2 and Exhibit D1, Tab 2 respectively. Refer to Exhibit A, Tab 13, Schedule 3 for an overview of the project and program approval process for Remotes.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, cost of power, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan is reviewed by the Executive Committee of Hydro One Inc. As necessary, underlying assumptions are modified and the results finalized and presented for approval to the Hydro One Inc. Board of Directors.

6.0 DEVELOPMENT OF DETAILED BUDGET

The final phase in the planning cycle is the budgeting phase, which focuses on fine-tuning of near-term, detailed information to facilitate plan implementation and monitoring of results for the year immediately following. During the budgeting phase, the cost impacts of any updated assumptions or work program requirements are examined and factored in as necessary.

APPENDIX A
COSTING ASSUMPTIONS

1.0 ECONOMICS

	2008	2009	2010	2011	2012	2013
CPI – Ontario (%)	1.6	2.3	2.0	2.1	2.0	2.0
Dx cost escalation for Construction (%)	4.8	1.9	1.1	1.9	2.2	2.2
Dx cost escalation for Operations & Maintenance (%)	2.1	(0.4)	(0.5)	1.1	1.6	1.7
Exchange Rate (CDN$/US$)	1.026	1.057	1.072	1.045	1.05	1.071

CPI-Ontario, and US cost escalators forecasts were based on the *Global Insight December 2007* forecast. The exchange rate forecast for 2008 was prepared based on the November 2007 edition of *Consensus Forecasts*; the remaining years were based upon the *Global Insight October 2007 Long-Term Forecast and Analysis.*

Dx cost escalators are based on Global Insight's 2nd quarter 2007 Power Planner. These escalators are used for general or other materials and services costing. Major material category escalations will be issued separately by Business Integration.

2.0 INTEREST RATES

	2008	2009	2010	2011	2012	2013
90-Day Banker's Acceptance Rate (%)	3.72	4.22	4.50	5.12	5.12	4.87
Interest Capitalized Remotes (%)	5.29	5.59	6.69	6.89	6.89	6.79

Interest cap rates: Tx, Dx, Remotes, Brampton – Forecast of Scotia Capital All-Corp Mid-Term Yield (from Treasury – December 14, 2007). Telecom – Forecast of 90-Day Banker's Acceptance rate plus 15 basis points.

3.0 CAPITAL OVERHEAD RATE

	2008	2009	2010	2011	2012	2013
Capital Overhead Rate - Remotes (%)	5.6	6.4	6.4	6.4	6.4	6.4

The capitalized overhead rates are based on an independent study by our cost allocation consultants. These rates may require adjustment if there is a significant change in the spending mix as the OM&A and Capital programs are finalized.

4.0 LABOUR ESCALATION

Note that the allowed financial impact of labour escalation is capped at 3% annually (this excludes the impact of changes in payroll burden costs) for **each** staff category (i.e. Society, PWU, MCP). If your subsidiary's labour escalation exceeds 3% in any staff category in any given year then reductions in other costs and/or staff will be required to offset the incremental increases.

Specific details on annual labour escalation are provided below.

(a) Society Staff

3% economic increases effective April 1, 2008, 2009, 2010, 2.5% increase effective April 1, 2011 and 2012. (There are COLA provisions in 2011 and 2012, but it's not possible to predict at this time whether they will trigger).

The former 1% performance pay increase has been eliminated. Automatic annual salary progressions will occur (in addition to the economic increases above) until staff reach the terminal step.

As of October 1, there were 842 Society represented staff, of whom 428 are at the terminal step.

Therefore, the remaining 414 staff will be entitled to annual progressions, averaging 5.35%.

For staff hired prior to October 1, 2007, annual progressions will occur on October 1 of subsequent years. For staff hired after October 1, 2007, annual progressions will occur on the anniversary of their hire date.

b) PWU staff

Anticipate economic increases of 3% effective April 1, 2008 and each subsequent year.

Step progressions - past experience (i.e. 2006) indicates that 9.4% of PWU receive progressions annually and that progressions result in a salary increase of 4.6%

(c) MCP staff

Anticipate 4% annual increase per year in base pay for the entire period.

(d) Incentive Plan Payouts

All incentive plans have been discontinued, with the exception of the MCP Short Term Incentive Plan. Payout under that plan is assumed to be 20% in all years.

5.0 HEADCOUNT PROJECTIONS – REGULAR AND NON-REGULAR STAFF

	2008	2009	2010	2011	2012	2013
Regular Staff	38	41	41	41	41	41
Non-Regular Staff	7	7	6	6	6	6
TOTAL REGULAR	**45**	**48**	**47**	**47**	**47**	**47**

6.0 BENEFIT COSTS RATES (PAYROLL BURDEN)

The forecast Hydro One burden rates for each subsidiary are shown below. Note that the dollar amounts and a more detailed breakdown are available upon request.

Company	Category	2008	2009	2010	2011	2012	2013
Remote Comm.	Non-Regular Staff % of total earnings*	5.44%	5.38%	5.43%	5.45%	5.46%	5.48%
	Regular Staff % of total earnings* % of base pensionable earnings**	5.44% 28.12%	5.38% 26.51%	5.43% 26.05%	5.45% 25.90%	5.46% 25.96%	5.48% 26.03%
	Pension % of base pensionable earnings	27.17%	26.60%	26.35%	26.20%	26.08%	25.94%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, OPRB (for Inergi where applicable), Ontario Health Premiums (OHP)

- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.
- Payroll burden rates exclude Powerflex benefits for MCP employees

7.0 INCOME & CAPITAL TAX RATES

	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Federal Tax Rate	19.50%	19.00%	18.00%	16.50%	15.00%	15.00%
Provincial Rate	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%
Total Statutory Tax Rate	33.50%	33.00%	32.00%	30.50%	29.00%	29.00%
Capital Tax Rate (1)	0.225%	0.225%	0.075%(2)	NIL	NIL	NIL

Note 1: Ontario introduced lower capital tax rates in its economic statement, retroactive to January 1, 2007. Bill 24 reflects these changes and has received first reading. PWC indicates that substantively enacted for accounting purposes is when a majority government tables legislation in the House of Commons. We are considering this as substantively enacted since the Liberals have a majority government in Ontario whose Bill 24 containing the capital tax changes that received 1st reading on December 13, 2007.

Note 2: Rate change effective January 1, 2010 and is eliminated July 1, 2010. This represents the weighted average.

ECONOMIC INDICATORS

1.0 INTRODUCTION

Appendix A of Exhibit A, Tab 13, Schedule 1 provides the costing assumptions underlying the 2009 Business Plans. This exhibit provides additional background with respect to these assumptions.

2.0 ECONOMIC INDICATORS

2.1 Remotes Cost Escalation for Construction, Operations and Maintenance

Remotes uses the Consumer Price Index (CPI) as a planning tool to forecast expenditure level changes.

The Consumer Price Index (CPI) provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation.

Remotes operates wholly in the Province of Ontario, Canada. As a result, the CPI–Ontario exhibits the inflationary environment in which Remotes operates. The CPI forecast is from Global Insight's December 2007 forecast and can be found in Table 1.

Table 1

	Historic			**Bridge**	**Test**
	2005	**2006**	**2007**	**2008**	**2009**
CPI – Ontario (%)	2.2	1.8	1.9	1.6	2.3

2.2 Exchange Rate (US$/CDN$)

Table 2 provides the 2005, 2006 and 2007 average exchange rates based on actual daily closing rates. The exchange rate forecast for 2008 was prepared based on the November 2007 edition of *Consensus Forecasts*. 2009 was prepared based on the *Global Insight October 2007 Long-Term Forecast and Analysis*.

Table 2

	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
Exchange Rate (US$/CDN$)	1.212	1.134	1.075	1.026	1.057

While the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

3.0 INTEREST RATES

Interest rate forecasts and existing debt are used to determine the cost of capital for Remotes as described in Exhibit B1, Tab 1, Schedule 1. Table 3 contains Remotes long term debt rate as issued to them from Hydro One Inc. on April 1, 1999 and refinanced in 2005.

Table 3

Particulars	Cost Rate (%)
Third Party long-term debt	5.60

3.1 Long-Term Debt Rates

Table 4 contains Hydro One Inc.'s historical and forecast long-term interest rates. For 2005, 2006 and 2007 each rate is derived by adding the average actual daily closing

Government of Canada bond yield for the applicable term (i.e. 5 year, 10 year or 30 year) to the corresponding Hydro One Inc. average actual credit spread.

Table 4

	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
5-Year					
Government of Canada %	3.58	4.10	4.21	3.04	3.34
Hydro One Credit Spread %	0.31	0.33	0.44	1.04	1.04
Hydro One Bond Interest Rate %	3.89	4.43	4.65	4.08	4.38
10-Year					
Government of Canada %	4.07	4.21	4.27	3.60	3.90
Hydro One Credit Spread %	0.50	0.51	0.60	1.17	1.17
Hydro One Bond Interest Rate %	4.57	4.72	4.87	4.77	5.07
30-Year					
Government of Canada %	4.43	4.27	4.31	4.10	4.40
Hydro One Credit Spread %	0.81	0.83	0.89	1.37	1.37
Hydro One Bond Interest Rate %	5.24	5.10	5.20	5.47	5.77

For 2008 and 2009, each rate is derived by adding the forecast Government of Canada bond yield to the corresponding Hydro One Inc. credit spread. The 10-year Government of Canada bond yield forecast for 2008 and 2009 is based on the April 2008 Consensus Forecasts. Other rates and spreads are determined as described below.

The 5 and 30-year Government of Canada bond yield forecasts are derived by adding the March 2008 average spreads (5-year to 10-year for the 5 year forecast and 30-year to 10-year for the 30-year forecast) to the 10-year Government of Canada bond yield forecast. This derivation is consistent with the Board's methodology in establishing the forecast for the 30-year Government of Canada yield, as employed in the formula based return on common equity approach for regulated utilities. Consistent with this methodology, Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for March 2008 obtained from our Medium Term Note program dealer group for each planned issuance term.

3.2 Deemed Long-Term Debt Rate

The deemed long-term debt rate is calculated as the Long Canada Bond Forecast plus the average spread on "A/BBB" rated corporate bonds as per the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006 (Cost of Capital Report).

The forecast for 2009 is derived by adding the 30-year Government of Canada forecast from Table 4 to the March 2008 spread between the average actual 30-year Government of Canada bond yield and the average DEX Long Term Corporate Bond Index – Yield inferred from the graph on www.pcbond.com

Table 5

	Test
	2009
30-year Government of Canada %	4.40
All Corporates Long -Term Bond Spread %	1.79
Deemed Long-Term Debt Rate %	6.19

3.3 Deemed Short-Term Debt Rate

The deemed short-term debt rate is the average of the 3-month bankers' acceptance (BA) rate plus a fixed spread of 25 basis points, as per the Cost of Capital Report, as shown in Table 6 below.

The forecast 3-month BA rate for 2009 is based on the forecast Government of Canada 3-month treasury bill rate from the April 2008 edition of *Consensus Forecasts* adjusted by the March 2008 average spread between 3-month BAs and 3-month treasury bills.

Table 6

	Test
	2009
3-month BA Rate % 25 basis point spread %	4.22 0.25
Deemed Short-Term debt Rate %	4.47

3.4 Allowance for Funds Used During Construction

For construction work in progress (CWIP), Remotes capitalizes interest at the Scotia Capital Inc. All Corporate Mid-Term Average Weighted Bond Yield as per the methodology approved by the Board in its letter dated November 28, 2006 in proceeding EB-2006-0117.

The rates for 2008 and 2009 the rates are calculated using the 10-year Government of Canada forecast from Table 4 plus the March 2008 spread between the 10-year Government of Canada bond yield and the average DEX mid-term Corporate Bond Index yield from www.pcbond.com.

Table 7

	Bridge	Test
	2008	**2009**
10-year Government of Canada % All Corporates Mid-Term Bond Spread%	3.60 1.69	3.90 1.69
All Corporates Mid-Term Yield%	5.29	5.59

4.0 INCOME AND CAPITAL TAX RATES

The historical and forecast tax rates are presented in Table 8. Please refer to Exhibit C2, Tab 6, Schedule 1, for the calculation of Remotes' income taxes and Exhibit C2, Tab 4, Schedule 1, for forecast year capital taxes.

Table 8

	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
Federal Tax Rate (%)	21.00	21.00	21.00	19.50	19.00
Federal Surtax Rate (%)	1.12	1.12	1.12	0	n/a
Provincial Rate (%)	14.00	14.00	14.00	14.00	14.00
Total Statutory Tax Rate (%)	**36.12**	**36.12**	**36.12**	**33.50**	**33.00**
Large Corporation Tax Rate (%)	0.175	n/a	n/a	n/a	n/a
Capital Tax Rate (%)	0.300	0.300	0.225	0.225	0.225

5.0 LABOUR ESCALATION RATES

Appendix A of Exhibit A, Tab 13, Schedule 1 provides the labour rate escalation assumptions for Remotes' three compensation categories: the Society of Energy Professionals ("Society"), the Power Workers Union ("PWU") and Management Compensation Plan ("MCP") staff.

For Management Compensation employees, escalation factors were provided by Remotes' senior management.

Escalation factors for PWU and Society staff reflect the current collective agreements, which were effective April 1, 2008 and July 1 , 2007 respectively.

6.0 COST RATES FOR BENEFITS

Appendix A of Exhibit A, Tab 13, Schedule 1 provides the benefit cost rates or payroll burden assumptions incorporated in the 2009 Business Plan. These rates are applied to the forecast labour rates.

The "burden rate," expressed as a percentage, estimates employee current and future cost rates for benefits which are attributable to labour in the current period, and allocates such costs across Hydro One legal entities. The benefit costs include:

(a) Other post-retirement benefits (OPRB), such as future health and dental costs;
(b) Other post-employment benefits (OPEB), such as long-term disability;
(c) Supplementary pension plan (SPP);
(d) Pension (funding) contributions;
(e) Employee benefit costs during active employment; and
(f) Statutory benefit payments, such as CPP, EI, etc.

Cost items (a) through (d) are actuarially determined by Hydro One Inc.'s external actuaries, Mercer Consulting Inc., using assumptions recommended by the actuaries and accepted by Hydro One Inc.'s management. Assumptions are determined with reference to past experience and industry norms.

Cost item (e) is based on estimates from Mercer, and from Hydro One Inc.'s insurance provider Great West Life, as to anticipated escalation factors of health and dental costs. These estimates are compared to past experience.

Cost item (f) is based on government schedules of premium rates for CPP, EI, etc.

PROJECT AND PROGRAM APPROVAL AND CONTROL

1.0 INTRODUCTION

As described in Exhibit A, Tab 13, Schedule 1, there are a number of key steps within the overall planning cycle which are typically completed prior to the development of more detailed project and program assessments. These prerequisite steps include: need identification, project/program prioritization, and development of preliminary work programs, based on estimates of project costs and benefits. Once the preliminary plans have been accepted at the proof-of-concept stage, an analysis of preferred alternatives and costs is completed for individual projects and programs. Business cases based on the analysis are prepared for review and approval.

2.0 PROJECT AND PROGRAM APPROVAL

Project and program proposals are prepared in the format of an Investment Justification Document (IJD) (please see sample Justification filed as Attachment A to this exhibit). This ensures consistent development and assessment of proposals. The IJD template includes such factors as the need for the investment, including the implications of not doing the work, the results to be obtained and the recommended solution and its cost. In determining the recommended solution, alternative approaches and project risks are considered. The factors considered include regulatory requirements, business efficiencies, and the impact on customers, system reliability, environment and safety, as well as any other relevant information. The investment justifications are then reviewed in a series of steps at the management and executive levels, depending on the dollar limit and significance of the investment, consistent with the Organizational Authority Register. The review and approval process is typically less formalized for small dollar, low impact investments with the exception of strategic investments all of which are reviewed by the Hydro One Board.

3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures. Deviations from plans are identified and corrective action taken. When a variance is not expected to be eliminated by the end of the project, a revised business case is prepared and the project is reviewed and re-justified based on the revised set of circumstances (cost, scope, schedule). Projects which cannot be re-justified are either scaled back, cancelled or otherwise adjusted to conform with the new situation.

Attachment A

Remote Communities (CAPITAL OR OM&A) Program - 2009

Investment Category: PROGRAM/PROJECT NAME

Description:

□ Business Case Summary Required

Budget/Cash Flow

Justification Details (check one)

□ Safety	□ Regulatory
□Customer/Reliability	□ Business Efficiency
□ Environment	□ Other

Financial Evaluation Results/Benefits to be achieved/delivered:

Need and Planning Assumptions:

If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code.

Alternatives Considered:

Risk Assessment of not doing the job:

Prepared by:

Approved by:

Date:

SERVICE QUALITY INDICATORS

1.0 INTRODUCTION

Subject to the exceptions and modifications noted below, Remotes currently monitors and reports service quality indicators as required in Chapter 15 of the *Ontario Energy Board 2006 Electricity Distribution Rate Handbook*. As of January 1, 2009, Remotes will monitor and report against the service quality requirements ("SQR") laid out in the amended Chapter 7 of the *Distribution System Code*, which comes into force on that date. Customer service indicators and service reliability indices are tracked monthly. Results are reported internally on a monthly basis. Reports are provided to the OEB annually in accordance with the *2006 Electricity Distribution Rate Handbook.*

Due to the distances between communities and the associated cost to transport staff and equipment, Remotes does not make appointments with individual customers. As a result, Remotes is not able to track the SQRs related to Appointment Scheduling and Appointments Met and Rescheduling of Missed after January 1, 2009. With respect to the SQR for service connections, service connections are typically planned through Band Council offices, are grouped together to reduce costs, and are performed on the day Remotes staff are in the community, or in a nearby community. The SQR is modified to reflect this.

Remotes' distribution system consists primarily of overhead conductors. Underground locates are rarely required. Therefore with respect to the SQR for underground locates, establishing this measure as a monthly performance target would not be indicative of overall service quality, and training staff to track the time between the request and the locate would be impractical as the work is very rarely performed. Remotes does not track or report this measure.

Remotes' Customer Service and Service Reliability results and targets from 2005 to 2008 are shown in Tables 1 and 2. Over the historical period, Remotes met all applicable OEB targets (ie for the measures tracked), with the exception of CAIDI in 2005 and 2006

1.1 Customer Service Indicators

Remotes tracks, analyzes and reports customer service indicators monthly, and results are reviewed with Remotes' President and CEO as part of our internal performance scorecard process. This process identifies areas of concern so that they can be immediately addressed and brought back in line with OEB requirements.

Analysis of monthly and annual result trends provides valuable information for work planning. The definitions of these indicators are provided in Section 2.1.

1.2 Service Reliability Indicators

Interruption data is collected and recorded in Remotes' Thunder Bay Service Centre, through communications with plant operators and field staff involved in the interruption restoration, and through the SCADA system, which records generation related outages. The data on outages and service quality is used to analyze performance, and drive strategy and business investment decisions.

Interruption data is used to calculate OEB reliability indices (see Section 2.2 for definitions) monthly which are reported internally.

Customer interruptions are analyzed and reported internally throughout the year.

2.0 DEFINITIONS

2.1 Customer Service Indicators

The Customer service indicators that Remotes uses are as follows:

2.1.1 <u>Connection of New Services:</u>

The percentage of customer connections of new services completed within 5 working days from the day on which all conditions of service are satisfied, including being able to schedule sufficient work in the community or in a nearby community to reduce the transportation costs.

2.1.2 <u>Emergency Response:</u>

The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for Rural utilities, and 60 minutes for urban utilities. Due to the nature of Remotes' service territory, Remotes is required to meet the 120 minutes response time. The elapsed time is measured from the call to the arrival of qualified Remotes' service personnel, and includes Remotes' agents.

2.1.3 <u>Telephone Accessibility:</u>

The percentage of calls answered by the call center within 30 seconds.

2.1.4 Written Response to Inquiries:

The percentage of responses to customers' (or an agent of the customer) requests for written information regarding their accounts that are met within 10 days of the request.

2.2 Service Reliability Indicators

The three Service Reliability Indicators are:

2.2.1 System Average Interruption Frequency Index (SAIFI):

The average number of times that customers served by Remotes were interrupted in the year. Due to the inherent lack of generation redundancy in an isolated system, service interruptions are more frequent in remote communities than in a grid connected context. Very short outages may be experienced when different generators are dispatched by the automated system.

2.2.2 System Average Interruption Duration Index (SAIDI):

The average numbers of hours that customers served by Remotes were without power in the year.

2.2.3 Customer Average Interruption Duration Time (CAIDI):

The average interruption duration (in hours) of customers who were interrupted.

The above reliability indices measure all interruptions caused by planned and unplanned interruptions of 1 minute or more.

2.3 Force Majeure

Remotes deems a *force majeure* to have occurred when a major catastrophic event beyond Remotes' control occurs that results in widespread system damage causing customer interruptions that affect an entire community or results in customers being without service for a duration of at least 12 hours.

A catastrophic event may be a storm or fire or any other problem that interrupts an entire community and causes a change in the normal restoration business processes.

All Remotes customers interrupted throughout the duration of the event while normal restoration business processes are suspended are counted in the determination of the numerator of the percent interrupted. The denominator is the total number of customers served at the end of the month when the force majeure occurred.

3.0 RESULTS

The results of the Customer Service Indicators and the three Service Reliability Indicators are attached in Tables 1 and 2 respectively.

3.1 Customer Service Indicators

Table 1 indicates customer service results, overall, remain consistent over the historical period and are better than the minimum OEB targets.

Table 1
Customer Service Indicators

Performance Measure	OEB Target	2005 Actual	2006 Actual	2007 Actual	2008 OEB Target
Connection of New Services (% completed in ≤ 5 days)	≥ 90	97	100	100	≥ 90
Emergency Response (% responded to in ≤ 120 min)	≥ 80	94	97	89	≥ 80
Telephone Accessibility (% answered in ≤ 30 seconds)	≥ 65	93	92	92	≥ 65
Written Response to Inquiries (% responded to in ≤ 10 days)	≥ 80	100	100	100	≥ 80

*Emergency Response results including the impact of Force Majeure.

3.2 Service Reliability Indicators

Table 2 shows the service reliability over the periods 2005 to 2007 and the targets for 2008.

Table 2
Service Reliability Indicators

Performance Measure	2005 OEB Tgt	2005 Act	2006 OEB Tgt	2006 Act	2007 OEB Tgt	2007 Act	2008 OEB Tgt
SAIFI *Frequency of Interruptions* (#of interruptions per customer)	≤ 19.9	12.9	≤ 19.9	10.6	≤ 15.6	13.5	≤ 15.6
SAIDI *Duration of Interruptions* (hrs of interruption per customer)	≤14.1	11.5	≤ 14.1	9.3	≤12.7	10.5	≤ 12.4

Performance Measure	2005 OEB Tgt	2005 Act	2006 OEB Tgt	2006 Act	2007 OEB Tgt	2007 Act	2008 OEB Tgt
CAIDI ***Average Interruption Time*** (#of hrs per interruption)	**≤ 0.7**	**0.9**	**≤ 0.7**	**0.9**	**≤ 0.8**	**0.8**	**≤ 0.8**

Over the historical period, SAIFI and SAIDI performance has been better than target. Since CAIDI is dependent on both SAIDI and SAIFI (mathematically CAIDI = SAIDI / SAIFI), the reduction in SAIFI (ie, the number of interruptions) can result in CAIDI being worse than target, as it was in 2006. .

STAKEHOLDER INFORMATION SESSION REPORT

1.0 OVERVIEW

On August 20, 2008, Remotes held an information session about its upcoming rate submission. Representatives from 14 First Nation communities were invited to participate, and 15 representatives from 9 communities were in attendance.

The main objectives of the consultation process were to inform customers about proposed changes to revenue requirement and to customer rates, to explain how to get involved in the OEB hearing process, and to learn about stakeholder issues.

2.0 SUMMARY OF DISCUSSIONS

This section provides a brief overview of the key topics of interest to stakeholders, the concerns raised and the responses provided.

2.1 Rate Impacts

Participants expressed concerns about the limited economic opportunities in remote communities and the impact of higher electricity costs on residential customers. Remotes explained that the submission attempts to balance the impact on Rural and Remote Rate Protection with the impact on customers. Participants also noted that increases to Standard A rates will affect the overall budgets for communities.

2.2 Cost Control

Participants were interested in discussing current and planned cost control measures. In particular, participants were interested in measures taken to control fuel costs and measures to increase the use of local resources to reduce staff transportation costs. Remotes explained that measures to control fuel cost increases included enhancing the efficiency of generating stations, improved use of winter roads, improved fuel supply contracts and the implementation of a customer demand management program. Remotes also stated that local resources were used when possible, especially for activities such as CDM assistance, brush cutting and construction projects.

2.3 Renewable Energy

Participants were interested in plans to develop renewable resources. Remotes stated that potential renewable resources have been identified in several communities, and that programs to develop these resources, in partnership with local First Nations, were planned for 2009.

2.4 Program Questions

Participants asked whether brush cutting programs were planned in 2009. Remotes stated that, in order to improve reliability, a cyclical forestry program, including brush cutting, was initiated in 2008 and was expected to continue in 2009. Questions were also raised about the Customer Advisory Board (CAB). Remotes explained that the CAB included residential and small business customers from six communities, that the CAB normally meets twice a year, and that members were selected through an application process initiated when ads were placed in the Wawatay newspaper.

2.5 Process Questions

Participants were interested in how to get involved and how they would be made aware of the rate hearing. Remotes noted that it was anticipated that the OEB would require Notice to be placed in Wawatay News in English, Ojibway, Oji Cree and Cree as had happened in previous proceedings. It was also noted that information about the rate filing would be available on Hydro One's web site.

3.0 LIST OF APPENDICES

APPENDIX A – List of Participants and Questions asked

APPENDIX B – Presentations

HYDRO ONE REMOTE COMMUNITIES INC.

INFORMATION SESSION – UPCOMING HO REMOTES RATE APPLICATION

Held at: Travelodge Airlane Hotel, 698 Arthur Street West, Thunder Bay

Held on: August 20, 2008 – 9:30-1:00

External Participants:

Wendy Nanokeesic	Kitchenuhmaykoosib (Big Trout Lake)
Cecilia Begg	Kitchenuhmaykoosib (Big Trout Lake)
Sidney Fiddler	Sandy Lake FN
Roy Spence	Webequie FN
Fred Barkman	Sachigo Lake FN
Joseph Tait	Sachigo Lake FN
Dan Chikane	North Caribou FN (Weagamow)
George Rae	Deer Lake FN
Johnny Meekis	Deer Lake FN
Thomas Beardy	Bearskin Lake FN
Eli Kakekayash	North Caribou FN (Weagamow)
James Mamakwa	Kingfisher Lake FN
Connie Thomas	Fort Severn FN
Abigail Matthews	Fort Severn FN
Joseph C. Meekis	Sandy Lake FN

Company Representatives:

Una O'Reilly	Hydro One Remote Communities Inc.
Jim Kirkpatrick	Hydro One Remote Communities Inc.
Ralph Falcioni	Hydro One Remote Communities Inc.
Sue Rob	Hydro One Remote Communities Inc.
Kevin Mann	Hydro One Remote Communities Inc.
Susan Frank	Hydro One Networks Inc.

This section summarizes questions and concerns raised during information session.

Rates

1. Given limited economic opportunities and resources in remote communities; why is the cost of electricity so high?
2. What is being done to stabilize costs and rates to customers?
3. How can the average customer afford further increases?
4. When will the new rates start?
5. How does the subsidy work?
6. How does the subsidy impact me?
7. Where does the subsidy show up on my bill?
8. What is the proposed increase?
9. Why is the rate increase 4.4%? and why is this necessary?
10. How are higher Standard A rates going to be paid given current funding systems?

Cost Control

1. Are on-site support and local resources being used effectively to control costs?
2. What is currently being done to control fuel costs?
3. What else can be done to reduce fuel costs?

Renewable Energy

1. Are there any hydro related economic opportunities for my community?
2. Are there any future planned RET developments?
3. Are RET's successful?
4. What is the role and responsibilities of Hydro One and the impacted First Nation communities with upcoming RET development?

Program Questions

1. Are there any brush cutting programs planned?
2. What it the role of CAB?
3. How often does the CAB meet?
4. How are the members on the CAB selected?

Process Questions

1. What is the relationship between the province, OEB, Hydro One, NAN and various tribal councils?
2. What consultation process does the OEB and Hydro One have with customers and First Nation communities?
3. What involvement do First Nation customers and communities have with regulations and policies?
4. Are Hydro One Remote Communities regularly audited?
5. Are the financial statements of Hydro One Remote Communities available?
6. When is the rate submission made?
7. What is the submission process?
8. When and how can I respond?
9. What papers will advertise the notice of application?

Hydro One Remote Communities Information Session

2009 Rate Submission

Why are we here?

- The Ontario Energy Board (OEB) is a provincial agency.
- The OEB regulates all electricity distributors.
- The OEB approves our budget, decides what projects we can do and tells us what we can charge customers.
- Every year, the OEB chooses Distributors whose budget and rates they will review.
- This year, the OEB chose Hydro One Remote Communities.

What happened in 2006?

hydro one

- Our last rate submission was in 2006.
- Conservation was the key issue:
  - introduced conservation rates,
  - set up a conservation program for customers.
- Our overall costs remained at the same level as in 2002.
- We did not increase customer rates or Rural and Remote Rate Protection

What has changed since 2006?

- Fuel costs have increased.
- We expect to start serving Marten Falls in 2008 or 2009.
- Our maintenance programs are expected to grow, both due to assets in our existing communities where generators are aging, and to respond to Marten Falls.

Overview of Changes ($M)

Item	2006	2009
Operations, Maintenance & Admin	10.6	14.3
Fuel	17.9	23.1
Depreciation & Amortization	4.8	4.5
Interest costs	2.0	1.7
Taxes	.3	1.6
Service Revenue Requirement	35.6	45.2
Less Remote Rate Protection	21.1	30.1
Revenues from Customers	14.5	15.1

What are our Values?

Vision

We will be the **BEST** off-grid utility measured against performance in Safety, Environment and Customer Loyalty.

What are our Values?

Mission

We are an off-grid electrical generation and distribution company focused on **customer satisfaction** and utilizing management systems to achieve **operational excellence**.

What are our Values?

Values

Safe work environment

Customers

Environmental responsibility

Employee development & recognition

Business integrity

Consistent fair treatment of customers and staff

Financial responsibility and accountability

Employee involvement in business and understanding of business drivers

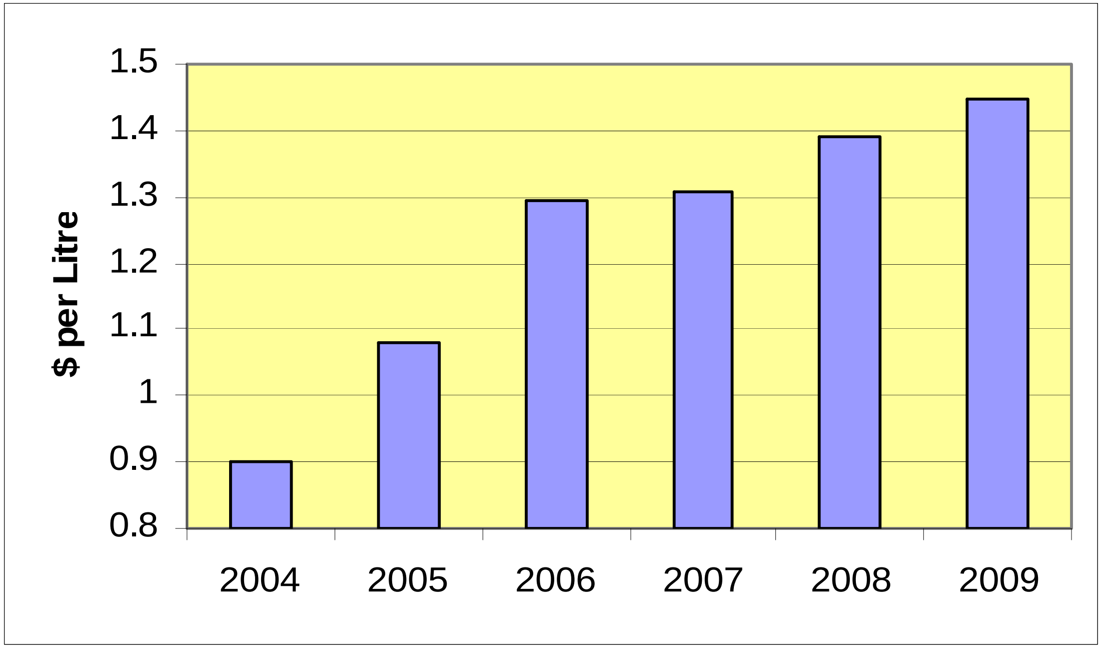
Continuous improvement

Rate Changes

- We believe that the increased costs should be shared between customers and RRRP.
- We understand that increase customer rates by the same average increase for customers in the rest of the province, in the range of 4-5%.
- For an average residential customer, this would represent an increase of about $5 per month.
- For the average Standard A customer this would represent an increase of about $57 per month.
- We are proposing a large increase in Remote Rate Protection.

Cost Pressures

Fuel Cost Increases



- Since 2004, the commodity price for diesel fuel has more than doubled.
- We have moderated the financial impact of these increases by improving winter road deliveries and our fuel delivery contracts, but the delivered price per litre has still increased by 60% over 2000 rates

Fuel and Transportation Costs

By 2009, diesel costs are expected to increase $5.2M over the OEB approved amount in 2006, accounting for over 50% of our costs.

Fuel price increases add to generation costs, and the cost to transport staff and equipment to our communities

A number of mitigation measures have been undertaken:

Increased flight coordination

Customer demand management program & improved station efficiency

Winter road fuel (3 million litres were transported this year, an increase of 1 million over previous years

Specific Programs

Operations, Maintenance & Admin

- Operations, Maintenance & Administration (OM&A) include the following cost categories:
  - Generation maintenance
  - Generation operation
  - Distribution maintenance
  - Customer care
  - Community Relations (Conservation, public safety & customer outreach)
  - Administrative expenses (legal, financial, information technology)

Generation Maintenance $5.6M

- We currently maintain 18 generation stations, 55 generators, 2 hydro electric stations and 4 windmills.
- We anticipate increased maintenance requirements in 2009 related to the inclusion of Marten Falls in our service territory, and to overall forecast of engine hours
- Planned engine maintenance prevents premature failure
  - Contributes to system reliability
  - Prescribed by engine manufacturers.
- Our planned maintenance program includes work on generators and auxiliary systems (fuel storage and transfer, ventilation, fire protection systems etc).
- Unplanned maintenance is based on historical costs and is required to respond to emergency outages.

Generation Operations $3.5M

- Generation operations are programs related to the day to day operation of the stations.
- This program includes costs related to station operators, who are responsible for routine maintenance, inspection and for on-site monitoring of fuel deliveries and for waste handling, transportation and disposal.
- Generation operations also includes environmental programs required to ensure that we comply with all legal and corporate requirements related to environmental protection.

Distribution $1.7M

- We operate 18 distinct and stand alone distribution systems.
- Distribution operations and maintenance programs include preventative maintenance, trouble calls, and metering.
- Planned maintenance includes line patrols, data collection and system condition assessment and corrective and preventative maintenance. All of these activities improve our reliability.
- We also introduced a forestry program this year. This program was developed in response to condition assessment work in 2007, and will keep our rights of way in an acceptable operating condition.

Customer Care $1.8M

- This program provides general customer account services

- It including meter reading, billing, collections, bad debts and responses to customer inquiries and complaints.

Community Relations $0.6M

- This program has three aspects: Conservation and Demand Management, the Customer Advisory Board and Public Safety/Joint Use activities.
- The Conservation and Demand Management program engages communities and customers in conservation activities and helps make energy efficient technologies available in communities. In 2007, this program helped customers save on their bills, saving over 1 million kWh of electricity, or 300,000 litres of fuel
- This program also provides for our Customer Advisory Board, which gives us an opportunity to discuss our policies and procedures with residential customers. Costs for this program are related to meeting costs.
- This program also provides for our joint use program, which ensures that cable and telephone companies who use our poles do so safely.

Generation Capital $4.0M

- Engine overhauls and replacements are planned in accordance with manufacturers' standards.
- New engines are more efficient, use less fuel and have lower emissions.
- Emergency System Breakdowns is a program that provides for replacements related to catastrophic failures of the distribution or generation systems and auxiliary systems.
- Design, Construction and Asset Management (DCAM) Program includes a number of projects to replace or improve stations, tank farms, secondary heat systems, computer control and monitoring systems and generation protection systems.
- DCAM projects will help improve our environmental performance and operating efficiency.
- Also proposing a hydroelectric partnership program to support local First Nations to develop renewable energy resources near their communities.

Current Standard A Rates

Standard A Residential Road Rail		**Standard A Residential Air Access**	
kWh Charge First 250 kWh	$0.5696	kWh Charge First 250 kWh	$0.7691
Over 250 kWh	$0.5822	Over 250 kWh	$0.8418
Standard A General Service Road Rail		**Standard A General Service Air Access**	
kWh charge	$0.5822	kWh charge	$0.8418

Current Non Standard A Rates

Residential Year Round			**General Service Single Phase**		
Monthly Charge		$16.45	Monthly Charge		$27.95
kWh	First 1,000	$0.0775	kWh	First 6,000	$0.0868
	Next 1,500	$0.1033		Next 7,000	$0.1150
	Over 2,500	$0.1300		Over 13,000	$0.1300
Residential Seasonal			**General Service Three Phase**		
Monthly Charge		$27.80	Monthly Charge		$35.00
kWh	First 1,000	$0.0775	kWh	First 25,000	$0.0868
	Next 1,500	$0.1033		Next 15,000	$0.1150
	Over 2,500	$0.1300		Over 40,000	$0.1300

Customers and Service Territory

20 Remote Communities are served by Hydro One

14 are First Nation Communities

12 are Air Access only

12 additional Independent First Nation Communities with Diesel systems

3,300 Customers

56 Diesel Generators

2 Mini-Hydro Stations

4 Wind mills

14 - 17 Million Litres Fuel

The communities of Whitesands and Collins are served through the Armstrong station

OEB Process for Reviewing an Application

- Utility files an Application
- The OEB issues Notice to inform potential participants
- The Board determines the "issues" in the proceeding
- Hearing takes place (either oral or written)
- The Board issues a Decision and Rate Order

Participation

- You ask for status within 10 days of your receipt of the Notice
- 3 classes of status/involvement
  - Intervenor
  - Observer
  - Letter of Comment

HOW DO PARTICIPANTS GET FUNDING?

Eligibility for Funding

Only Intervenors are eligible for funding.

You must indicate in your letter of intervention that you wish to be declared eligible for costs and provide reasons.

Under the Ontario Energy Board's rules, you may be found eligible if you primarily represent the direct interests of consumers (e.g. ratepayers) in relation to regulated services or if you represent a public interest relevant to the Board's mandate

Ontario Energy Board Maximum Reimbursement Rates

Maximum Hourly Rates for Lawyers

Provider of Legal Services	Completed Years Practising	Maximum Hourly Rate
Lawyer	20+	$330
Lawyer	11 to 19	$290
Lawyer	6 to 10	$230
Lawyer	0 to 5	$170
Articling Student/Paralegal		$100

Maximum Hourly Rates for Consultants

Provider of Legal Services	Completed Years Practising	Maximum Hourly Rate
Analyst/Consultant	20+	$330
Analyst/Consultant	11 to 19	$290
Analyst/Consultant	6 to 10	$230
Analyst/Consultant	0 to 5	$170
Case Management		$170

The Board may also provide an honorarium to recognize individual efforts with the amount of any such honorarium set by the OEB panel which presides over the review of the application

Disbursements

Reasonable disbursements, such as postage, photocopying, transcript costs, travel and accommodation, directly related to the party's participation in the process, will be allowed.

Factors considered by the OEB in determining compensation

- You participated responsibly in the process;

- You made reasonable efforts to co-operate with other parties in order to reduce the duplication of evidence and questions on cross-examination;

- You contributed to a better understanding by the Board of one or more of the issues addressed by the party;

For more information

Please visits the Ontario Energy Board website –
www.oeb.gov.on.ca

or the Hydro One Networks Regulatory web page –
http://www.hydroonenetworks.com/en/regulatory/

<u>Potential Issues for the Hydro One Remote Communities Inc.
Rate Application</u>

1. Is the requested increase in revenue requirement appropriate?

2. Is Hydro One Remote Communities Inc. investment in environmental protection measures appropriate?

3. Can Hydro One Remote Communities Inc. introduce cost-saving efficiencies in its diesel fuel procurement, delivery and management?

4. Are the contributions to Hydro One Remote Communities operating costs from customers and from the Rural and Remote Rate Protection ("RRRP") subsidy reasonable?

5. In light of increases to distribution rates which the Board is permitting to other Ontario electricity distributors, are proposed increases to customer rates appropriate?

PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

To be filed behind this tab as and when Procedural Orders, correspondence, Notices are filed.

LIST OF WITNESSES

(To be determined)

CURRICULUM VITAE

(To be determined**)**

EXHIBIT LIST

Exh	Tab	Schedule	Contents
A			**Administration**
	1	1	Application
	2	1	Summary of Application
		2	Financial Summary
	3	1	Summary of Remote Business
	4	1	Notices of Motion
	5	1	Compliance with Licence and OEB Filing Requirements for Electricity Distributors
	6	1	Distribution and Generation Licence
		2	Minister's Letter to Marten Falls
	7	1	Service Area Map
	8	1	Corporate Organization Charts
		2	Hydro One Governance Framework
		3	Affiliate Service Agreements
	9	1	Remotes Financial Statements - Historic Years (2005, 2006 and 2007)
	10	1	Hydro One Inc. - Annual Reports (2005, 2006 and 2007)
		2	Reconciliation of Regulatory Financial Results with Audited Financial Statements
		3	2007 Distribution Financial Statements Reconciled to USofA Trial Balance

COST OF CAPITAL

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing of Remotes' capital requirements for the 2009 test year.

2.0 CAPITAL STRUCTURE

Consistent with the Board's Decision in RP-1998-0001, Remotes is 100% debt-financed and is operated as a break-even company. Remotes does not plan to seek a return on equity. As such, Remotes' cost of capital is based on 100% debt, consisting of 4% deemed short term debt and 96% long term debt.

Long term debt includes $23 million of long term debt issued to Hydro One Inc, reflecting debt issued by Hydro One Inc. to third party public debt investors, and $6.9 million of deemed long term debt.

3.0 DEEMED SHORT-TERM DEBT

The Board has determined that the deemed amount of short-term debt that should be factored into rate setting be fixed at 4% of rate base, and that the deemed short-term debt rate be based on the forecast three-month bankers' acceptance rate plus a fixed spread of 25 basis points. For 2009, the deemed short-term rate is 4.47%, using the April 2008 Consensus Forecast. Remotes assumes that the deemed short term debt rate for each test year will be updated in accordance with the Board's December 20, 2006 Cost of Capital Report.[1], upon the final decision in this case.

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[1] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, Ontario Energy Board, Docket No. EB-2006-0088/EB-2006-0089, issued December 20, 2006.

4.0 THIRD PARTY LONG-TERM DEBT

Remotes' original $23 million of third party long term debt matched the actual terms of a note issued by Hydro One Inc. on April 1, 1999, to the Ontario Electricity Financial Corporation (successor to Ontario Hydro) in consideration of the assets transferred. This note had a coupon rate of 7.75% and matured in November 2005. Hydro One refinanced it with new debt issued to the public during 2005. The new debt has a maturity date of May 19, 2036, an interest coupon rate of 5.36% per annum and an effective cost rate of 5.60%, including issuance costs such as issue discount, agency commissions, and interest rate hedge related costs.

5.0 DEEMED LONG-TERM DEBT

Deemed long-term debt of $6,913 thousand in 2009 consists of any affiliate debt callable on demand, as well as the remaining amount of debt required to balance the total financing with the rate base. Consistent with the Board's Cost of Capital report, the deemed long term rate is to be applied to any affiliate debt callable on demand. The deemed long-term debt rate for 2009 is 6.19% based on the approach in Appendix A of the Cost of Capital report, using the April 2008 Consensus Forecast. Remotes assumes that in accordance with the Cost of Capital report, upon the final decision in this case, the deemed long term debt rate for each test year will be set based on the Consensus Forecasts, Bank of Canada and Long term Bond Yields – All Corporates from TSX Inc. data three months in advance of the effective date for the rate change.

6.0 COST OF CAPITAL SUMMARY

Remotes' 2009 rate base is $31,159 thousand which results in an after tax required return on rate base of 5.68%, as shown in table below.

2009 Cost of Capital

Particulars	($000s)	%	Cost Rate (%)	Return %	Return ($000)
Deemed short-term debt	1,246	4.0%	4.47%	0.18%	56
Third Party long-term debt	23,000	73.8%	5.60%	4.13%	1,288
Deemed long-term debt	6,913	22.2%	6.19%	1.37%	428
Total	31,159	100%		5.68%	$1,772

The historical debt summary schedules have been provided at Exhibit B2, Tab 1, Schedule 1.

HYDRO ONE NETWORKS INC.
Cost of Long-Term Debt
Test Year (2009)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/08 ($Millions)	Total Amount Outstanding at 12/31/09 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	19-May-05	5.360%	20-May-36	23.0	0.8	22.2	96.44	5.60%	23.0	23.0	23.0	1.3	

COST OF SERVICE SUMMARY

1.0 INTRODUCTION

This evidence presents an overview of Remotes Cost of Service evidence. The Cost of Service submissions include the following components:

- Operation, Maintenance and Administration ("OM&A") expenses
- Depreciation and Amortization Expense
- Payments in Lieu of Corporate Income Taxes
- External Costs

Each of these components is separately addressed within the company's evidence. Exhibit reference numbers are provided below.

Remotes' forecast cost of service has been developed consistent with its corporate objectives. The Company's planning process is described in detail at Exhibit A, Tab 13, Schedule 1.

1.1 Operation, Maintenance and Administration Expenses (OM&A)

Total OM&A expenses for the 2009 test year are $36,016 thousand.

Remotes plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the company. Exhibits in support of OM&A costs have been prepared by program area, and appear within the submitted evidence as follows:

Program Areas	2009 Total Cost ($000s)	Reference
Summary of OM&A Expenses	**$36,016**	**Exhibit C1, Tab 2, Sch 1**
Generation	$30,897	Exhibit C1, Tab 2, Sch 2
Distribution	$1,648	Exhibit C1, Tab 2, Sch 3
Customer Care	$1,800	Exhibit C1, Tab 2, Sch 4
Community Relations	$599	Exhibit C1, Tab 2, Sch 5
Administration and Other	$981	Exhibit C1, Tab 2, Sch 6
External Costs	$90	Exhibit C1, Tab 2, Sch 7

In order to satisfy the requirements of the *2006 Electricity Distribution Rate Handbook* and the *Filing Requirements for Transmission and Distribution Applications* (November 14, 2006), Exhibit C2, Tab 2, Schedule 1 identifies OM&A costs by grouped USofA accounts.

1.2 Resourcing

Labour costs are charged to OM&A and Capital work programs using standard labour rates. The evidence contained at Exhibit C1, Tab 3, Schedule 1 and Exhibit C2, Tab 3, Schedule 1 presents total staff levels and costs incurred by the company. Exhibit C1, Tab 6, Schedule 1 describes standard labour rates.

1.3 Corporate Cost Allocation

Hydro One Networks Inc. provides common services to Distribution and Transmission and other subsidiaries, including Remotes, on a centralized basis. The costs of these services and assets are assigned to business units on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so.

In RP-2005-0020/EB-2005-0378, Hydro One Distribution commissioned R.J. Rudden Associates to establish a cost allocation approach for Common Costs, which would be in accordance with accepted industry standards. The Common Corporate Cost Allocation Study determined the appropriate allocation of these shared costs between the business units of Hydro One. The study and its methodologies were accepted by the OEB in its Decision with Reasons dated April 12, 2006. The evidence included herein on common corporate costs uses this methodology and is shown in Exhibit C1, Tab 6, Schedule 1.

Exhibit D1, Tab 2, Schedule 1 provides evidence regarding the derivation of Overhead Capitalization Rates.

1.4 Depreciation and Amortization Expense

In RP-2005-0020/EB-2005-0378, Hydro One filed the Foster Associates Inc. depreciation study, the methodologies and associated costs flows from which were accepted by the OEB in its subsequent Decision with Reasons. The results of this study form the basis of the depreciation submission in this application. The company is proposing to recover $4,469 thousand in depreciation and amortization expense. Remotes' evidence on depreciation expense is filed at Exhibit C1, Tab 4, Schedule 1.

1.5 Payments in Lieu of Corporate Income Taxes

As a result of *the Electricity Act, 1998*, Remotes has been required to pay proxy taxes since 1999. Evidence outlining the calculation of Payments in Lieu of Income Taxes of $223 thousand appears at Exhibit C2, Tab 6, Schedule 1.

SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The requested OM&A expenditures result from a business planning and work prioritization process that reflects risk-based decision making to ensure that appropriate, environmentally responsible, and cost effective solutions are in place. This process is described in detail at Exhibit A, Tab 13, Schedule 1.

The proposed OM&A programs are required to meet public and employee safety objectives, to comply with the Distribution System Code and Government direction, to protect the environment, to maintain service quality and reliability at targeted performance levels, and to ensure public confidence as stewards of the assets entrusted to us.

Remotes' OM&A budget is grouped into different investment categories: Generation, Distribution, Customer Care, Community Relations, Administration and Other OM&A and External Costs. Table 1 provides a summary of Remotes' OM&A expenditures for the historical, bridge and test years.

Table 1
Summary of OM&A Budget ($000s)

Description	Historic (Actual)			Bridge	Test
	2005	2006	2007	2008	2009
Generation	22,184	26,421	27,386	31,699	30,897
Distribution	1,461	1,540	1,241	1,757	1,648
Customer Care	3,394	4,394	1,874	1,637	1,800
Community Relations	238	214	413	577	599
Administration and Other OM&A	794	1,026	877	983	981
External Costs	43	64	49	83	90
TOTAL	28,114	33,659	31,840	36,736	36,016

Note: The Summary of OM&A (Exhibit C1, Tab 2, Schedule 1) and Generation OM&A (Exhibit C1, Tab 2, Schedule 2) have been updated with revised forecasts for both bridge and test years based on a materiality threshold of 1% of 2007 year-end OM&A, or $125 thousand. Changes to the other supporting OM&A exhibits (Exhibits C1, Tab 2, Schedules 3 – 6) do not meet the materiality threshold and thus they have not been updated, however the updated numbers are reflected in the revenue requirement calculation.

Total OM&A expenditures are expected to decrease by 2% or $721 thousand over the 2008 to 2009 period. This is due primarily to lower anticipated diesel fuel prices in 2009 compared to 2008, partly offset by the additional costs related to the inclusion of Marten Falls as of July 1, 2009.

Detailed descriptions of the work activities in each area of Remotes OM&A expense and the reasons for the changes in costs over the 2005 to 2009 period are discussed in the schedules that make up Exhibit C1, Tab 2.

2.0 GENERATION

The Generation OM&A budget represents costs required to maintain and operate the existing generation stations and associated facilities to meet community loads. The proposed costs are intended to ensure that the overall reliability of the generating assets is maintained and that customer commitments are achieved, and that all legislative, regulatory and safety requirements are met. The generation OM&A budget includes investments designed to ensure that Remotes complies with all environmental requirements and to improve environmental performance, including the use of bio-diesel at all sites by the end of 2009.

Details of the expenditures under this program are provided at Exhibit C1, Tab 2, Schedule 2.

3.0 DISTRIBUTION

The Distribution OM&A budget represents planned maintenance, forestry and right-of-way maintenance, trouble response, data collection and system condition assessment, and meter re-verification, testing and checking. The proposed costs are intended to ensure that the overall reliability of the distribution systems is improved, that customer commitments are met, and that all legislative, regulatory, environmental and safety requirements are met. Details of the expenditures under this program are described in detail at Exhibit C1, Tab 2, Schedule 3.

4.0 CUSTOMER CARE

The Customer Care OM&A expenses represent the costs associated with meter reading, customer billing, collections and bad debt expenses. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 4.

5.0 COMMUNITY RELATIONS

The Community Relations OM&A work program includes CDM programs, outreach activities, Customer Advisory Board ("CAB"), and community safety program. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

6.0 ADMINISTRATION AND OTHER OM&A

The Administration and Other OM&A costs include the common corporate functions and services to support the Remotes business, as well as the maintenance of existing infrastructure, including business systems, facilities, and information technology. The common corporate functions and services include the provision of financial, human resource, legal, information technology and strategic planning services. Other OM&A programs also include the credits for overheads capitalized. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 6.

7.0 EXTERNAL COSTS

Remotes performs a small amount of unregulated external work. There are three main areas of work: assistance to the Electricity Safety Authority to facilitate inspections of Remotes' distribution systems and of customer installations; maintenance of street lights and First Nation owned generating equipment in Remotes service territory; and assessments of the Independent Power Authority generating stations (First Nation owned and operated generating stations in remote communities Remotes does not serve). External work is described in Exhibit C1, Tab 2, Schedule 7.

GENERATION OM&A

1.0 INTRODUCTION

Due to the lack of grid connection, Remotes is a generator of electricity to meet its obligations under section 29 of the *Electricity Act, 1998*. Diesel generation is currently the prime source of electricity within the communities. Remote also owns and operates two run-of-the-river mini-hydro electric generating facilities and has four demonstration project windmills. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost effective technology.

There are presently 55 diesel generators in service, ranging in size from 85kW to 1100kW. Most stations have three generators, sized to meet community load at different times of the day. Automated operation ensures that the generation units are run to maximize fuel efficiency by matching the generator size to the community load. Depending on electrical demand, Remotes handles 14 to 17 million litres of fuel each year.

Remotes has fuel storage tanks ("tank farms") within each community to ensure adequate diesel fuel supply. Tanks are equipped with measurement and alarm devices to reduce the risk of fuel spills and to enhance fuel control measurement. Most tanks are double-walled to enhance containment.

Due to the high cost of transportation to the communities, Remotes staff generally reside in the communities while undertaking planned and unplanned maintenance. Remotes maintains staff houses and trailers at 14 sites. A staff house is also planned in Marten Falls, to be built by the First Nation and maintained by Remotes. Commercial accommodations are used at the other sites.

The proposed Generation OM&A expenditures are $..30,897 thousand and include $21,649 thousand for diesel fuel required to generate electricity. The proposed OM&A expenditures are driven by such factors as the need to meet customer, regulatory and statutory requirements regarding service and reliability.

2.0 OVERVIEW

The Operation & Maintenance spending for historic, bridge and test years are presented in the table below.

Table 1
Generation Operation & Maintenance OM&A
($000s)

Category	Historic			Bridge	Test
	2005	2006	2007	2008	2009
Generation Maintenance	4,282	4,353	4,843	5,329	5,803
Generation Operations	2,613	3,460	3,224	3,389	3,445
Fuel	15,289	18,608	19,319	22,981	21,649
Total	22,814	26,421	27,386	31,669	30,897

2.1 Generation Maintenance

Generation maintenance related to structures includes minor civil repair work (required to maintain all generating station buildings, fences, yard sites and staff houses), annual inspections, and bi-annual sampling of water facilities for the staff houses and generation stations.

Planned maintenance prevents premature equipment and system failures and contributes to service reliability. Planned maintenance of diesel generating units is prescribed by the engine manufacturer. Intensive maintenance procedures are scheduled based on engine hours and vary from year to year. Regular maintenance is also performed on the run-of-the-river hydro stations.

Planned maintenance of tank farms includes expenditures to maintain the Generating Station fuel offload, bulk storage tanks and fuel transfer equipment. Planned maintenance of auxiliary systems includes secondary heating, primary cooling, ventilation, overhead crane inspections and fire protection systems.

Planned engine maintenance expense is based on a forecast of engine hours. The forecast for engine maintenance varies according to actual load in the community and the hours each engine is picked to run by the automated control system. Increases in Generation maintenance between 2008 and 2009 are related to increases in planned engine maintenance ($106K) and environmental improvements associated with waste heat projects ($115K) and failure analysis ($100K).

Generation maintenance also includes expenditures related to Renewable Energy Partnerships. Remotes believes that local First Nations must be involved in the development of renewable energy within their communities, and that they should benefit from these developments. Remotes has been working with First Nations to assess renewable energy sites. Remotes proposes to enter into Power Purchase Agreements with the First Nations (and private sector partners as applicable) and would buy electricity generated at a price based on the avoided cost of diesel fuel.

There are several potential small hydro-electric renewable sites within Remote’s service territory. Hydraulic generation potential of these sites is in the range of 500 kW to 1500 kW, and the sites are available for development by local First Nation communities. Wind resources may also be sufficient to support wind generation in some communities. Remotes plans to work with local First Nations to develop preliminary engineering assessments of these resources. These developments could reduce reliance on diesel fuel and improve environmental performance while fostering business relationships with local First Nation partners. $253 thousand is included in 2009 for studies and assessments of potential sites.

Unplanned maintenance is also included in generating and electric plant expenditures, and is comprised of maintenance and repair related to trouble reports and equipment or component failures.

2.2 Generation Operations

Generation operations represent expenditures required for safe and reliable day-to-day operation of the generating plants, and are required to keep the generating station and associated facilities in a standard operating condition as required to meet community load. This is associated with Remotes' responsibilities prescribed by the Electrification Agreements, the Certificate of Approval to Operate the Generating Station under the *Environmental Protection Act*, and Section 6.2.27 of the Distribution System Code.

Within each community Remotes contracts for local operators, who perform regular routine inspection of equipment at generating facilities including the generating units, auxiliary equipment and the bulk storage tank farm. The operators provide on-site monitoring of fuel deliveries, and the handling, transportation and disposal of waste. Operators are also responsible for keeping the stations clean, undertaking filter changes, checking diesel plants and reporting problems to the Thunder Bay Service Centre.

Generation operations also include a variety of environmental programs. These programs are conducted to ensure that Remotes is compliant with all legal and corporate requirements related to environmental protection, including obtaining and respecting

Certificates of Approvals and permits for the transportation of dangerous goods and with various reporting requirements under the *Environmental Protection Act.*

In 1999, Remotes developed an Environmental Management System ("EMS") to help improve environmental performance. In the course of developing and implementing the EMS, Remotes has transformed itself into an environmental leader, recognized provincially and nationally for its environmental record. In 2001, Remotes was awarded the Canadian Council of Ministers of Environment national Pollution Prevention award for small business in Canada. In 2002, Remotes achieved ISO 14001 registration of its EMS. This international registration is in addition to the significant environmental improvements achieved since implementing EMS. The EMS requires regular audits of the environmental system, spills prevention, support and training for staff and agents, and public communications.

The increase in generation operations in 2008 relates to environmental expenses associated with the clean up, investigation and monitoring of a large fuel spill at the Kingfisher station early in the year ($263K). A subsurface site investigation was undertaken and it appears that the fuel is contained under the station. An extensive monitoring program is required to ensure that immediate remedial steps can be undertaken if the fuel begins to migrate from under the station. The increase in generation operations in 2009 is related to the renegotiation of operator contracts, partly offset by lower expenditures related to the Kingfisher fuel spill.

2.3 Forecast of Fuel Usage and Load.

Remotes forecasts load in order to plan for and meet customer loads, to estimate customer revenues and to forecast its fuel and maintenance costs. As a result of Remotes' break-even business model, cost and revenue differences between forecast loads and forecast fuel costs do not result in a profit or loss to Remotes, but are added to or drawn from the Rural and Remote Rate Protection Variance Account.

In order to forecast its fuel costs, Remotes compiles a usage/load forecast using a combined and comprehensive approach. The usage forecast forms the basis of fuel litres required, fuel costs, and assists in the generation planning and upgrade process.

Remotes tracks actual historical data on energy usage by community, customer class, and time period. This historical data provides the baseline starting point for forecasting usage/KWH sold. Adjustments are made to this baseline data on a go-forward basis using items such as average usage growth, expected customer changes and impacts of conservation programs. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads. Historical averages, growth patterns, and seasonal adjustments also impact the forecast.

Forecast revenues are calculated based on the rate class usage characteristics and the applicable rate schedules.

Table 2 below shows the actual and forecast for the 20 communities Remotes currently serves plus the addition of Marten Falls for the 2009 test year, and a forecast of consumption for street lighting.

Table 2
Forecast Electricity Consumption by Consumer
(000s)

	Historic			**Bridge**	**Test**
Community	**2005**	**2006**	**2007**	**2008**	**2009**
Armstrong	4,028	3,800	3,702	3,784	3,801
Bearskin	2,343	2,525	2,683	2,615	2,677
Big Trout	5,084	5,323	5,500	5,567	5,635
Biscotasing	382	337	361	375	377
Deer Lake	4,053	3,814	4,159	4,332	4,393
Fort Severn	2,388	2,449	2,463	2,600	2,624
Gull Bay	798	763	966	953	993
Hillsport	243	273	275	268	269
Kasabonika	3,479	3,695	3,869	4,117	4,175
Kingfisher	1,814	1,886	1,954	1,965	1,983
Lansdowne	2,004	1,777	1,760	1,878	1,898
Marten Falls	N/A	N/A	N/A	NA	996
Oba	276	251	238	240	242
Sachigo	2,845	2,762	2,510	2,555	2,609
Sandy lake	10,349	10,455	10,333	10,672	11,574
Sultan	446	439	465	462	464
Wapekeka	2,003	2,196	2,206	2,368	2,394
Weagamow	4,008	3,900	4,022	4,218	4,244
Webequie	2,692	2,829	2,951	3,021	3,112
Street Lights	182	206	202	170	185
TOTAL	**49,417**	**49,680**	**50,619**	**52,160**	**54,644**

* includes Collins and Whitesand

Significant variances in 2009 from prior years include Sandy Lake's spike due to increased customer connections, and the introduction of Marten Falls.

The Usage Forecast (kWh's sold) forms the basis of the fuel forecast. Once kWh's sold are established, historic operating fuel efficiency ratios and load loss rates are utilized to forecast generated kWh's and fuel litres required. The fuel forecast is done on a site by site basis, given different load characteristics, plant efficiency and community load loss. Estimates are made as to expected delivery method based on historical trends and vendor/supplier data. Fuel prices are derived via existing vendor contracts and the outlook for fuel commodity prices. Expected fuel costs are also impacted by the available storage in each community

2.4 Fuel Costs

Overall fuel costs are affected by three main factors: price, delivery and volume. Two of these factors can be influenced by Remotes (costs of delivery and volume), and Remotes has several initiatives underway to address these. For example, Remotes has introduced a customer demand management program, is making engine and station efficiency improvements, has increased use of winter road deliveries when available, and has improved supplier contracts that give Remotes access to competitive delivery contracts. Remotes is also negotiating with INAC and local First Nations to increase storage capacity when station capacity upgrades are undertaken to increase the availability of cheaper, winter road fuel. Fuel commodity prices, on the other hand, are the result of market forces and are not within Remotes' control.

In order to reduce diesel fuel usage, Remotes has done the following things:

- Introduced a CDM program
- Operated and introduced Renewable Energy Technologies ("RET") generation facilities
- Improved fuel generating efficiency through SCADA technology and a proactive scheduled maintenance program.
- Maintained an active generation asset replacement program, and introducing more efficient technology

In order to mitigate the impact of rising fuel rates Remotes has done the following things:

- Negotiated long-term fuel delivery contracts with multiple suppliers
- Negotiated fuel delivery contracts directly with First Nation communities

- Maximized winter road deliveries (cheaper delivery methods) where possible through supplier relationships and improved tank storage

In 2009, Remotes plans several capital projects that will improve the efficiency of its diesel fuel usage. These projects are described in detail in Exhibit D1, Tab 2, Schedule 1.

LAND ASSESSMENT AND REMEDIATION

In 1998, the Board approved Remotes' Land Assessment and Remediation ("LAR") program to address historical liabilities associated with Remotes' operations. The LAR program involves assessment of historically contaminated lands, the implementation of remedial measures to treat, remove or otherwise manage the contamination found on and off-site and the implementation of on-site management controls to mitigate future off-site property impacts. Most of the contamination at Remotes' site is associated with historic spills of diesel fuel.

Table 1

Land Assessment and Remediation Expense	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
	1,238	915	983	1,335	1,500

Table 1 shows historic bridge and test expenditures of LAR. Remotes has recognized these amounts as a regulatory asset, thus the costs are zeroed out of generation expenses. In 2005, an extensive project to remove and remediate contaminated soil in Kasabonika Lake was completed ($423K). In 2008, the removal and remediation of the Attawapiskat Tank ($150K) and the initiation of a major remediation of the old generating station in Sandy Lake ($200K) are planned. In 2009, the Sandy Lake remediation is expected to be completed ($500K).

Information of the recognition of LAR is found in Exhibit C1, Tab 4, Schedule 1

LAR projects are normally planned to coincide with major capital projects such as generation upgrades and extend over multiple years. As such, variances in year over year expense are typical, based on the timing of these discrete projects. In 2009, a remediation project is planned in Sandy Lake.

DISTRIBUTION OM&A

1.0 INTRODUCTION

Remotes served 3,332 customers at the end of 2007 through 18 isolated distribution systems to serve 20 communities. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. The distribution systems are isolated, distinct and stand-alone, the result of the distance between each community. These distribution systems operate at distribution voltages ranging from 4.8 kV to 25 kV.

The distribution in-service assets maintained by Remotes include approximately 210 kilometers of line and transformers distributed throughout the system, which are used for voltage transformation.

The proposed OM&A expenditures are driven by such factors as the need to meet customer, regulatory and statutory requirements regarding service and reliability. A description of Remotes' planning process is provided at Exhibit A, Tab 13, Schedule 1.

Table 1
Distribution OM&A
($000s)

Category	**Historic**			**Bridge**	**Test**
	2005	**2006**	**2007**	**2008**	**2009**
Distribution Maintenance	1,303	1,391	1,154	1,530	1,474
Distribution Operations	158	150	87	238	192
Total	1,461	1,540	1,241	1,768	1,666

Distribution maintenance activities include both planned and unplanned maintenance, and trouble calls. Unplanned power interruptions on the distribution system generally result from line component failures and contact from trees or animals. Unplanned maintenance is reactive and varies due to external factors such as storms, variability in equipment deterioration and random equipment failures.

Planned maintenance includes line patrols, data collection and system condition assessment, and corrective and preventative maintenance. The Distribution System Code, Appendix C, requires that all local distribution companies patrol their distribution lines to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism. Implementation of an ongoing, more robust asset condition assessment program in 2008 ($116K) is expected to improve work planning and trouble response. Expenditures in this area also include verification of joint use construction and administration of Joint Use Agreements with Bell Canada and other joint use tenants as required by O.Reg. 22/04 and O.Reg. 272/04 made under the *Electricity Act, 1998*. Preventive maintenance includes equipment maintenance that is primarily cyclical in nature, including maintenance of equipment (line reclosers and line regulators).

Condition assessment work in 2007 defined a three to five year right-of-way maintenance cycle which will improve right-of-way clearances and distribution system reliability. The Armstrong to Collins line, in particular, requires significant initial clearing that is scheduled over a two year period. This maintenance is required to keep the distribution right-of-way in an acceptable operating condition which is the utility's responsibility as prescribed by Section 4.4 of the Distribution System Code. Variances between 2007 and 2008 are attributable to the implementation of the cyclical forestry program which is expected to last for three to five years ($292K).

Revenue metering is federally regulated under the *Electricity and Gas Inspection Act* and is governed by Measurement Canada. Under Measurement Canada regulations, all revenue meters must be approved and routinely inspected and maintained. Remotes complies with Measurement Canada rules and regulations. Every few years, meters must be removed from service to verify that they are performing accurately and within specifications. Electricity customers require a meter to measure their electricity usage, and the proper functioning of billing meters is essential to ensure customers are neither over-billed nor under-billed. Remotes is planning to make initial capital investment in smart meters in 2009, however, the impact on OM&A will not occur until future years.

CUSTOMER CARE OM&A

1.0 INTRODUCTION

Remotes provides general customer account services including in-community customer service activities to all customers connected to its distribution system. These services are established by Remotes' Distribution Licence, rate schedules, and in the Codes and Rules established by the Board, and are documented in Remotes' Conditions of Service. Remotes' customer care team is responsible for billing, collections, meter reading, and responding to customer inquiries and complaints.

The Customer Care spending for historic, bridge and test years is shown in Table 1 below. Bad Debt expense is included in the Customer Care OM&A category.

Table 1
Customer Care OM&A
($ Thousands)

Category	Historic			Bridge	Test
	2005	2006	2007	2008	2009
Customer Care	1,201	1,187	1,002	1,147	1,230
Bad Debt	2,193	3,207	872	525	575
Total	3,394	4,394	1,874	1,672	1,805

2.0 CUSTOMER CARE

Customer care expenses include costs to read meters, bill customers, collect on outstanding accounts and respond to customer inquiries. Remotes has two staff in the Thunder Bay service centre who are responsible for entering meter readings into the

Customer Service System, answering customer calls and inquiries, entering bill payments, organizing collection trips, contacting customers and band councils prior to collection activity and negotiating payment arrangements. Field staff undertake collection activities in the communities. Meter reading is contracted out through Band Councils to individuals in the communities.

Customer Care spending in test year 2009 is budgeted to be up approximately 7% compared with the 2008 bridge year because of anticipated costs related to implementing rates in 2009 ($100K). Bridge year spending in turn is expected to be about 14% higher than the 2007 actual due to the anticipated costs associated with the inclusion of Marten Falls in Remotes' service territory. The forecast increases in 2008 and 2009, however, follow a significant decrease in actual spending of almost 15% in 2007 and a 1% decrease in 2006, year over year. These decreases were the result of more efficient collections. Seen in context, therefore, the 2009 test year expense is only 3.6% above the 2006 amount.

3.0 BAD DEBT

Bad debt expense is made up of direct write offs offset by recoveries, plus the provision adjustment. The provision is an allowance taken against receivables where full recovery is in doubt. At the end of 2007, Remotes had $11.8 million in energy accounts receivable and of this amount, $8.7 million, or 74.2% were significantly aged (over 240 days old). A further $0.8 million, or 6.5% were over 119 days old. The bad debt allowance is based on a combination of applying a model percentage against outstanding energy accounts receivables and specific identification of high risk receivables. Adjustments to this allowance are charged to bad debt expense.

The large amounts for bad debt expense in 2005, 2006 and 2007 are primarily related to the need to establish a provision for bad debts related to Standard A arrears. Standard A (i.e., government) accounts make up approximately 13% of customers (by number) but account for 93% of the outstanding arrears (based on 2007 figures). Prior to 2005, Remotes did not disconnect Standard A accounts in arrears, did not write off outstanding balances and did not have an adequate provision for bad debts related to First Nation Band (Standard A) accounts in arrears, as it was believed that Indian and Northern Affairs Canada ("INAC") would backstop amounts due from First Nation Band accounts. Following a meeting with Officials from INAC in 2005, Remotes' understanding of INAC's position changed, such that it became clear that INAC would no longer backstop amounts due from First Nations. As a result of this change in understanding, Remotes increased its provision for bad debts in 2006, using allowance rates on previous actual payment history, the normal payment curve and specific adjustments for large or unusual receivables using management judgment. The external financial auditor accepted this approach. There are significant challenges and uncertainties related to the collection of Standard A arrears. Remotes has set a target to reduce outstanding Standard A arrears by 15% each year, with some success. Payment plan arrangements and federal government support for these arrangements are being negotiated, but there are limited options available to address these arrears, as arrears relate primarily to essential services such as nursing stations, water and sewage facilities and schools.

Over the past four years, Remotes has been very successful in reducing non-Standard A residential arrears, which make up 7% of the outstanding arrears based on 2007 figures and has worked closely with Band Councils and with residential customers to improve payment of these accounts, but collections are expected to be an ongoing challenge. Most non-Standard A customers do not have bank accounts and are economically disadvantaged. For many of these customers, electricity is the only utility service for which they are billed, making education about the importance of paying bills an ongoing necessity.

Overall, bad debt expense is expected to be lower in 2008 and 2009 as Remotes expects to continue to negotiate payment arrangements with First Nation Band Councils, and an adequate provision for Standard A accounts has now been established. The level of bad debt in 2008 and 2009 is expected to be required given the significant age of outstanding arrears. The forecast level reflects historical payment trends and historical write-offs and recoveries. Direct account write-offs averaged $0.6 million in the 2005-2007 periods. Remotes recovers accounts that were previously written off when the customer reconnects to the system, or if the customer sets up an account in another community or residence.

COMMUNITY RELATIONS OPERATIONS, MAINTENANCE AND ADMINISTRATION

Community Relations expenses include various customer outreach activities, including the Conservation and Demand Management (CDM) program, the Customer Advisory Board ("CAB") and public safety measures such as the joint use program.

Table 1
Community Relations
($000s)

Category	Historic			Bridge	Test
	2005	2006	2007	2008	2009
Total	238	214	413	577	599

1.0 CONSERVATION AND DEMAND MANAGEMENT

Remotes' CDM program was approved as part of its ongoing revenue requirement in its last rate application (RP-2005-0020/EB-2005/0497). Remotes has partnered with the Ontario Power Authority (OPA) to deliver energy efficient products in the remote north, but believes that because of the importance of conservation activities in achieving cost efficiencies, and because the OPA's focus is necessarily on the integrated transmission system, that a continued CDM program funded through Remotes' revenue requirement is a key aspect of meeting customer energy requirements going forward. The energy conservation program involves the delivery of energy conservation and demand management strategies that are designed to have a measurable impact on energy consumption rates as well as to develop local expertise within the community itself. This program reduces energy costs for customers, and program initiatives are subject to a Total Resource Cost test, as required by the OEB. CDM program expenses have grown as the programs are established and mature and more communities are included in conservation activities.

Remotes' customer conservation program is designed to develop sustainable conservation by developing local expertise and buy-in within communities. Remotes' program has mainly focused on conservation and energy efficiency awareness and on an ongoing pilot program to engage communities in energy planning and to deploy energy efficient appliances within these communities.

The conservation and energy efficiency awareness is focused on educating customers about how to save energy. This information is provided through bill inserts, community meetings and school presentations. In 2006, Remotes implemented "conservation rates," an inclining block rate structure that offers price signals to show customers the financial benefits of conserving energy. Last year, Remotes partnered with First Nation Band Councils to deploy Power Cost Monitors. These monitors allow customers to see how much electricity they use and to understand what it costs. Each Band Council has a supply of monitors and loans them out to residents to ensure that the maximum number of customers can use them.

Remotes also has a more in-depth program, the pilot program, which involves engaging the community in a baseline energy study so they understand the way they use energy currently, what it costs, and what alternatives might exist. Part of this baseline study identifies conservation related savings. Remotes hires and trains a local coordinator to implement some of these findings. The study may also identify renewable energy opportunities that the community can consider developing. Remotes includes three communities a year in this program and expects eventually that all communities will participate.

Last year, Remotes' customer conservation programs helped customers conserve over one million kWh of electricity which saved over 300,000 liters of diesel fuel.

2.0 CUSTOMER ADVISORY BOARD

The CAB offers a sounding board for discussion of service policies and procedures. The CAB members are residential and commercial customers from within Remotes' service territory. The CAB provides staff with insight into the way customers perceive Remotes' policies and procedures, and offers advice on how to improve those policies. Costs for this program are related primarily to mailing, meeting facilities, transportation to meetings and travel expenses for CAB members.

This program is expected to increase over the next few years as communities are brought into the mix. Cost increase relate to an increase in the number of meeting held throughout the year.

3.0 OTHER

Community Safety expenses relate primarily to the joint use agreements with local cable and television companies,

ADMINISTRATION AND OTHER COSTS

Administration and other costs include common corporate functions and services, telecommunications, enterprise technology, supply management services and project costs. Remotes local administration costs (e.g. for Thunder Bay Office and staff) are included in the work programs.

Allocation of common costs to each Hydro One affiliate, including Remotes, is based on clearly articulated shared services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Enterprise Technology Services, Telecommunications Services, and Supply Management Services to support the Remotes business.

Corporate Common Functions and Services include finance, human resources, legal, communications, risk management, internal audit, regulatory, corporate management activities, strategic planning and real estate facility services.

In 2005, Hydro One commissioned a study by R. J. Rudden Associates ("Rudden") to determine a methodology to allocate common costs among the business entities using the common services. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received.

This methodology was approved by the Board in the previous Hydro One Distribution rate decision RP-2005-0020/EB-2005-0378. The Board also considered it reasonable for Hydro One to employ the Rudden methodology in its subsequent Transmission rate application; this was done in EB-2006-0501. Remotes' test year submission in this Application reflects the same Rudden study methodology.

Cost drivers were selected on the basis of cost causation. Where this methodology could not be implemented or established, cost drivers were based on benefits received. Other factors considered in assigning cost drivers included practicality, stability, and materiality.

As a result of the Rudden study, approximately 30% of the total Corporate Common Functions and Services OM&A expenditures have been directly assigned to the appropriate Hydro One business units. The remaining 70% have been allocated based on the established cost drivers.

Remotes' management participated in the study on behalf of the Remotes business, reviewed the model and the results, and was satisfied that the overall allocation is reasonable.

Common Corporate Costs that can be directly assigned to an OM&A program, such as billing, are directly assigned to that program and deducted from Administration and Other Costs. Common Corporate Costs that are attributable to capital projects are capitalized, as discussed in Exhibit D, Schedule 2, Tab1.

Included in Administrative and General Expenses are project costs that occur from time to time.

Table 1
Remotes' Administrative and General Expenses
($000s)

Category	Historic			Bridge	Test
	2005	2006	2007	2008	2009
CCFS	515	684	644	772	905
Telecommunications Services	79	163	126	118	141
Enterprise Technology Services	435	359	341	310	379
Supply Management Services	247	67	61	64	95
Sub-Total	1,277	1,273	1,172	1,263	1,519
Less Direct Allocations	(246)	(68)	(86)	(43)	(86)
Less Capitalized OM&A	(237)	(179)	(209)	(237)	(452)
Total	**794**	**1,026**	**877**	**983**	**981**

The increase in CCFS costs is driven by the introduction of the Aboriginal Relations department, and higher Finance costs resulting from the International Financial Reporting Standards ("IFRS") conversion project and increased compliance costs. The Telecommunications allocation increase relates to higher costs relating to bandwidth, networking and voice services. The increase in Enterprise Technology relates to IT programs implemented to improve management planning, design and layout. Supply Management Services costs increases as the result of an overall program cost increase at Hydro One Networks relating to headcount.

Direct Allocations represent costs that can be directly assigned to projects such as customer billing and the cost to transport materials and are thus removed from

Administration. Capitalized OM&A are projected to increase a result of both increased capital spending and an increased overhead rate.

EXTERNAL WORK

1.0 OVERVIEW

Remotes performs a small amount of unregulated external work. There are three main areas of work: assistance to the Electricity Safety Authority to facilitate inspections of Remotes' distribution systems and of customer installations; maintenance of street lights and First Nation owned generating equipment in Remotes service territory; and assessments of the Independent Power Authority generating stations (First Nation owned and operated generating stations in remote communities Remotes does not serve). These assessments are undertaken in cooperation with INAC and the Nishnawbe Aski Development Fund. These assessments identify operational risks and efficiency measures that could be undertaken by INAC or the local First Nation. Costs related to external work are shown in Table 1, below. Revenues from external work are an offset to revenue requirement and are discussed in Exhibit E3, Tab 1, Schedule 1.

Table 1
Costs Related to External, Unregulated Work
($000s)

Historic Years			Bridge	Test
2005	**2006**	**2007**	**2008**	**2009**
43	64	49	83	90

CORPORATE STAFFING

1.0 OVERVIEW

Remotes' work is currently performed by regular staff, hiring hall staff, services purchased from Hydro One Networks, contracts with external firms who provide engineering and environmental services and by contracts for services with local communities, for agents and meter readers, and for casual resources related to land assessment and remediation, construction and CDM projects. Approximately 40% of Remotes' work is performed by non-regular resources.

Remotes currently has 38 full-time, regular staff. Full-time regular staff perform the following functions: design and manage generation and distribution assets; construction planning, project management and commissioning; environmental management and support services; financial support and services; management of the CDM program; community/customer policies and procedures; customer outreach, contact and billing/collection services; work execution, planning and management/supervision; skilled electrical and mechanical trades work involved with generation equipment; and fuel and material inventory management. In 2009, due to an increased work program related to increased maintenance requirements and an expanded capital program, along with the increasing complexity of negotiations related to INAC funded capital projects, headcount is forecast to increase to 41. This hiring is expected to lead to a decrease in contracted work with external engineering firms.

Remotes contracts with Hydro One Networks for Human Resources services. This contract gives Remotes access to a greater pool of employees than would otherwise be the case for a small utility. Remotes also benefits from established recruitment, apprenticeship and training programs, and from opportunities to employ skilled staff on a temporary basis (on rotations for example). Remotes also secures 24 hour trouble response services, legal services, Information Technology Services, Corporate Accounting Services, Safety and Work Methods and Training Services from Hydro One Networks under Service Level Agreements. These agreements allow Remotes to access professional and trades staff required on a less than full-time basis.

Contracts with First Nation Agents/Operators through band offices provide the following functions: minor maintenance on diesel generators; initial emergency response and assessment; fuel delivery, receipting and inventory monitoring; diesel station and staff house janitorial work; and meter reading. Casual labor is also secured through band offices for translation and logistical assistance for community /customer meetings, for the conservation program and to work on construction projects and on Land Assessment and Remediation projects. Remotes plans to have 41 regular staff in 2009 to respond to the increased complexity of negotiations with INAC and First Nations related to capital projects and an ongoing increased in overall work programs including an expanded capital program and expected increases in maintenance work. As discussed below in Staffing Strategy, overlap in some functions to prepare for pending retirements is also partly responsible for the increase in headcount.

As mentioned above, local resources in communities read meters, act as plant operators and provide assistance to construction projects, CDM projects and other local initiatives.

2.0 STAFFING STRUCTURE

Remotes has seven main categories of labor resources:

(i) PWU represented staff: The PWU is an industrial union that represents the trades, technicians and clerical workers. Within Remotes, PWU staff perform line work, electrical, mechanical, protection and control, civil, stock keeping, other technical and clerical/administrative work. These include Hydro One electrical maintainers, line maintainers, mechanical maintainers, engineering technicians and administrative employees.

(ii) Society represented staff: The Society is a professional union that represents engineers, accounting, technical, administrative and supervisory staff. They perform engineering, high level technical and administrative work as well as supervisory functions.

(iii) Management staff, who are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

(iv) Temporary Employees who are employees performing work in any of the three categories set out above and who are engaged in work that is not of a continuing nature.

(v) Contracted Staff are individuals engaged as independent contractors and are not on Remotes' payroll. They are engaged at Hydro One for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked and charged to Remotes by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions where applicable.

(vi) Station operator agents and meter readers are community-based resources normally contracted through the local Band Council. Station operators are responsible for routine inspections of the diesel plants; minor maintenance such as changing oil filters; reporting station problems to the Thunder Bay service centre; monitoring fuel deliveries; emergency response; and the safe handling and disposal of waste. Remotes has an agent and a back up agent for each station. Meter readers are responsible for reading meters and for reporting meter readings to the Thunder Bay Service Centre. Remotes has a meter reader in each community.

(vii) Casual workers are used for building projects, Land Assessment and Remediation projects and CDM projects. Casual workers may be acquired through the PWU hiring hall, or contracted through local Band Councils, depending on the type of work and skills available in the community.

Information on wages, salaries and overtime related to regular employees can be found in Exhibit C1 Tab 3 Schedule 2.

3.0 STAFFING STRATEGY

Remotes' greatest corporate risk with respect to its human resources is an aging workforce and, with a world-wide scarcity of core skills in the industry, a highly competitive labour market. Over the next five years, approximately 40% of Remotes' staff are eligible for an undiscounted retirement. This is a trend which is consistent with challenges faced by other utilities in the electricity sector throughout the world. Recent studies suggest that up to half the workforce in the North American electricity industry will be eligible for retirement in the next five years[1].

Due to the nature of Remotes' service territory, and the extensive travel and time away from home that may be required, staff recruitment can be challenging. Remotes tends to have a number of regular staff positions that are essentially "one of" positions. This means that if an employee leaves the company to retire or to pursue other opportunities, Remotes' work program can be negatively affected until job duties are mastered by the departing employee's replacement.

To address this risk, Remotes participates in training apprentices and new graduates hired by Hydro One Networks, and has, in recent years, acquired additional resources through the hiring hall or engineering firms and recruited externally to obtain experienced trades,

[1] Lester B Lave et al, The Aging Workforce: Electricity Industry Challenges and Solutions, Electr J. (2007), doi: 10.1016/j.tej.2006.12.007

technical and professional staff. Remotes is also planning to have some overlap between new employees and retiring employees so that a skill transfer can take place.

Due to the impact of the above-noted factors as well as increased workload, total pay costs (per Exhibit C2 Tab3 Schedule 1) are forecast to increase by about 11% in the 2009 test year compared with the 2008 bridge year. This increase is driven largely by the increase in headcount to 41 full-time staff from 38, as discussed in the Overview above. On a cost per employee basis, test year 2009 pay costs are budgeted to remain flat except for a 3% inflationary adjustment.

Total pay costs are forecast to increase by less than 3% in the 2008 bridge year compared with the 2007 actual year, as headcount remains static at 38 full-time staff. The increase in total pay reflects inflation and a slight change in staff make-up between Society, PWU and Management.

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of Remotes' depreciation and amortization expense for the 2009 test year.

Remotes has adopted the depreciation and amortization expense methodology which Hydro One Distribution submitted evidence for in its 2006 test year submission, RP-2005-0020/EB-2005-0378, by filing an independent study by Foster Associates which was completed in June 2005. The Ontario Energy Board (OEB) accepted the costs flowing from the Depreciation Study.

2.0 DEPRECIATION EXPENSE

The aforementioned Foster methodology was used in determining the depreciation expense for the 2009 test year.

Detailed depreciation schedules are filed at Exhibit C2, Tab 5, Schedule 1.

Table 1
Depreciation Expense
$ Thousand

Description	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
Depreciation On Fixed Assets	2,343	2,550	2,486	2,554	2,762
Asset Removal Costs	122	186	204	106	207
Losses/(Gains)				(6)	
Total	2,465	2,736	2,690	2,654	2,969

The increase in 2009 depreciation expense amount relative to the 2008 amount is due to the higher level of fixed assets in service and costs associated with the removal of generating stations at road sites in 2009.

Fixed asset removal costs are charged to depreciation expense on an "as incurred" basis.

3.0 AMORTIZATION EXPENSE

Amortization expense pertains to costs the Board has allowed Remotes to defer for recognition at a future date. The Board has, in past decisions, approved the amount of the cost to be deferred for future recovery, the prescribed period or method of amortization, and prescribed time period over which the costs in each account should be amortized.

Historical, bridge and test year amortization schedules are filed at Exhibit C2, Tab 5, Schedule 1.

Table 2
Remotes Amortization Expense
$ Thousand

Description	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
Other Post Employment Benefits	329	329	329	329	0
Environmental Assets	1,238	915	983	1,335	1,500
Total	1,567	1,244	1,312	1,664	1,500

3.1 Environmental Assets

Remotes recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Since these expenditures are expected to be recoverable in future rates, Remotes has recognized an equivalent amount as a regulatory asset. This balance is amortized on a basis consistent with the pattern of actual expenditures expected to be incurred each year, currently estimated to continue until the year 2015. Remotes reviews its estimates of future environmental expenditures on an ongoing basis. There is a corresponding credit to OM&A for the environmental asset expenditures and this is discussed further in Exhibit C1, Tab 2, Schedule 2.

PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

Under the *Electricity Act, 1998*, Remotes is required to make payments in lieu of corporate income taxes (PILS) relating to taxable income earned by its distribution and generation business. The Ontario Energy Board (OEB) has directed that the taxes payable method should also be used for regulatory purposes (2006 EDR Handbook section 7.1 "OEB 2006 regulatory expense methodology").

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILS income tax payable being different than the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers at that time.

The 2009 Remotes regulatory tax calculation has been prepared in accordance with the 2006 EDR Handbook and the 2006 EDR Tax Model.

2.0 INCOME TAX RATE (FEDERAL AND ONTARIO):

A combined rate of 33% has been used for 2009 (Federal 19% and Ontario 14%). In 2008, a combined rate of 33.50% was in effect, whereas, prior to 2008, a combined income tax rate of 36.12% had been in effect from 2004.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

A reconciliation between the regulatory Net Income Before Tax ("NIBT") and taxable income for the test year 2009 is provided in Exhibit C2, Tab 6, Schedule 1, Attachment A. This schedule contains the income tax component of the PILS computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation, capital cost allowance ("CCA") etc.

A reconciliation between the accounting NIBT and taxable income for the historical years is provided in Exhibit C2, Tab 6, Schedule 1, Attachment C.

In order to make it easier for parties to follow the historic reconciliations, we have grouped adjustments made to regulatory NIBT to arrive at taxable income into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement or for which appropriate tax adjustments are made (e.g. depreciation vs. CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and

5) Items where the impact is immaterial in total, and as such, have not been included in our business plan (applicable to test year only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of the Remotes taxable income is the NIBT as shown on the utility's income statement for the year. There are typically many adjustments that are made to the NIBT to arrive at taxable income, since the NIBT is prepared using Canadian generally accepted accounting principles and taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes (includes items such as depreciation, contingent liabilities, accounting provisions such as OPEB etc.) and is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT (includes items such as CCA, the deductible portion of capitalized overhead, environmental and OPEB payments etc).

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes. This is a key point in comparing the historical years tax return data to that computed for the test year, since the tax return NIBT has been increased (or reduced) by amounts that have not been added (or deducted) in computing the regulatory NIBT (e.g. contingent liabilities, capitalized interest). That is, for test year 2009, only differences between the tax and accounting rules related to costs included in either the regulatory revenue requirement or rate base (e.g. CCA, capitalized overhead) are adjusted in arriving at taxable income.

5.0 TREAMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities (i.e. on their balance sheet) for foregone revenue or for expenses that have been incurred for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the OEB often through a rate rider process.

For example, assuming that a $100 expense is incurred at a 35% tax rate, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the OEB subsequently approves recovery of these expenses over a four year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income/expense has been taxed or deducted in different years.

	Year 1	Year 2	Year 3	Year 4	Year 5	CUM
Income (deduction)	(100)	25	25	25	25	nil
Tax refund (payable)	35	(8.75)	(8.75)	(8.75)	(8.75)	nil
Cash inflow (outflow)	(65)	16.25	16.25	16.25	16.25	nil

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the *"2006 EDR Handbook Report of the Board"* issued May 11, 2005 (Page 61) that stated as follows: "A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (e.g. obsolescence provisions, lawsuits, staff reductions, etc.), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward with NIBT either decreasing or increasing respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

No changes were forecast in those contingent liabilities reflected in 2009 and as such, it is not necessary to adjust the 2009 NIBT for contingent liabilities in computing taxable income. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

7.0 ONTARIO CAPITAL TAX

Remotes pays Ontario capital tax on its taxable capital as defined by the Corporations Tax Act (Ontario). However, for regulatory purposes, it recovers capital tax computed by reference to its rate base net of the applicable Ontario exemption, as directed by the OEB. Please refer to Exhibit C2, Tab 4, Schedule 1 for the calculation of the Ontario capital tax. For 2007, the bridge and test years the Ontario capital tax rate of 0.225% is used. This compares to a capital tax rate of 0.3% applicable to historical years prior to 2007.

The Ontario exemption is allocated amongst the related regulated entities, based on rate base.

COSTING OF WORK

1.0 OVERVIEW

Remotes work program is comprised primarily of activities associated with labour, equipment, material acquisition and sundry. Consistent with common industry practice, trade labour and equipment hours are distributed directly to benefiting programs and projects by using weekly-prepared timesheets. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

In terms of material and contract costs, a material surcharge is included in this cost category to capture material and contract services procurement costs benefiting the particular program or project. In the case of distribution capital projects and external sales, a freight surcharge is also included to distribute the freight costs associated with the winter road delivery of distribution line materials into the remote communities.

As twelve of the communities Remotes serve are not accessible by year round road, staff, equipment and cargo are transported to the communities by aircraft, Remotes contracts out passenger and cargo transportation services. Flight costs are charged to the project that the personnel are working on with efficiencies achieved by co-ordination of work crew scheduling whenever possible.

Remotes staff most often stay several days at a time in the company's staff house in the remote community in which they are working. To efficiently reflect the cost of food to direct work, food expense is allocated to all projects in which there are labour hours incurred by trade and technical staff.

In terms of estimating and costing capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. The cost of removal work is accounted for as Depreciation and Amortization and customer contributions are netted against our gross capital costs. Capital work also receives a monthly charge for its share of Corporate Common Functions and Services, overhead costs and capitalized interest where applicable.

2.0 PROJECT / PROGRAM MAJOR COST CATEGORIES

2.1 Standard Labour Rates

On an annual basis, Remotes standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components; forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll costs include allowances (as per negotiated contracts), company benefits, Government obligations and contractual time away from work (vacation, statutory holidays, sick leave) costs along with an assignment of Remote administrative costs, are divided by the forecast billable hours, to create the Remotes standard labour rates. The cost elements embedded in the standard rate are illustrated in Table 1 and explained in the pages following, using the Remotes Technician and Maintainer rate as an example.

Remote Communities Technician and Maintainer – Regular Staff 2009 Forecasted Labour Rate	**Billable $ per Hr.**
Composition Of Standard Labour Rate	$205
Payroll Obligations	$68
Non-Labour Administration Costs	$29
Non-Project, Administration, Management and Support Services Labour	$108

2.1.1 Payroll Obligations ($68)

A brief description of the cost elements included in this category is provided below.

Labour and Payroll Allowances (69% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in our wage schedules.
- Overtime: Contractually negotiated.
- Payroll Allowances: Allowances are also contractually negotiated and stated in our collective agreements. Regular staff (PWU) are entitled to travel, footwear and on-call allowances. Casual trades are entitled to travel and subsistence allowances where circumstances permit. Staff are also entitled to Northern and Remote overnight and lodging allowances when working directly in communities served by local diesel generation.

Company Benefits (27% of Payroll Obligations)

- Regular Staff: Comprised of Pension (26.6% of base pensionable earnings) and current and post employment benefits; health, dental, etc. (26.5 % of base pensionable earnings).

- Non-Regular Staff (eg: Lines Hiring Hall): Pension and Welfare contributions that are 40% lower in comparison to the company benefit contributions made on behalf of the regular employee.

Government Obligations (4% of Payroll Obligations)

- Consists of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board (WSIB);
- In 2009, 5.38 percent is to be applied against total earnings (includes base pay, bonus, overtime, benefits and taxable allowances) to recover these costs.

2.1.2 Non Labour Administration Costs ($29)

This category consists primarily of non-labour expenses incurred by the business necessary for the business operations. This includes non-direct CF&S fees, facility costs related to the main office which includes property taxes, utilities, telephone, insurance, maintenance, materials and supplies. It also includes items such as travel, training, advertising, postage, office supplies and low value computer equipment and services. Non-Labour administration costs are based on historical trends and consider current company initiatives.

2.1.3 Non-Project, Administration and Support Services Labour ($108)

This category consists of labour cost incurred in non-project, administrative, management or support service roles. These costs include management and technical staff providing support services to manage and monitor the status of the assigned programs and projects. Some other functions include finance, stock-keeping, fuel management and flight logistics. Additionally, it includes time for attendance at safety meetings, housekeeping and downtime often resulting from inclement weather. This category includes employee vacation and statutory holidays, all established and identified in our collective agreements. Sickness and accident costs are also included. These estimates are based on historical trends and consider current company initiatives.

2.2 Transport & Work Equipment (T&WE)

Remotes utilizes Hydro One owned fleet assets as per the conditions of its Service Level Agreement (SLA) with Hydro One Networks Inc. This SLA is for fleet management, maintenance, repair and rental services relating to the use of transport and work equipment used by Remotes. Remotes also incur the cost of transporting T&WE into the remote locations as well as flight costs associated with sending the Hydro One Networks Inc. Fleet Mechanic to these locations. Each equipment class has a standard equipment rate which is calculated by dividing the annual forecast cost by the annual forecast hours the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program.

2009 TWE Cost Forecast (including SLA)	$545,000
2009 Forecasted TWE Hours	9860
2009 Average TWE Rate/Hour	$55

2.3 Material Costs and Surcharges

Material costs charged to a project or program are based on the issue cost from Inventory, which is the Average Unit Price (AUP) or the direct-shipped purchase order price. On a monthly basis, the total monthly material and contract charges are surcharged with a fixed percentage to cost effectively recover the Corporate Common Functions and Services (CCF&S) cost allocation to Remotes for services provided by Supply Management Services. These are costs associated with purchasing, negotiating contracts and transportation management. The percentage rate is derived by assigning the costs of Supply Management Services to projects based on an annual material and contract forecast. The 2009 forecasted SMS rate is 2.5%.

A freight surcharge is applied to all distribution capital and external work in order to allocate freight costs incurred for winter road delivery of distribution inventory line materials to remote communities. The percentage rate is derived by using the forecasted freight expense and projected material expense for planned distribution capital.

2.4 Sundry – Passenger Flight Costs and Meals

The cost of transporting staff to remote locations is charged to the project that is benefiting from this expense. This service is tendered to obtain the most cost competitive contract. Efficiencies are achieved with coordinating the schedule of work and work groups to share flights.

In order to carry out operating, maintenance and capital work activities, it is necessary for trade and technical staff to stay overnight in remote communities at Remotes staff houses on an ongoing basis. Food supplies are required and the cost of these supplies is allocated to direct work programs based on labour hours charged by the two primary trade and technical labour groups. The rate per hour is based on forecasted meal expense and planned labour hours.

HYDRO ONE REMOTE COMMUNITIES INC.

Cost of Service
Historical (2005, 2006, 2007), Bridge (2008) and Test (2009) Years
Year Ending December 31
($000s)

Line No.	Particulars	2005	2006	2007	2008	2009
		(a)	(b)	(c)	(e)	(f)
1	Total Operation, Maintenance & Administrative Expenses	28,114	33,660	31,840	36,736	36,016
2	Depreciation & Amortization Expenses	4,032	3,980	4,002	4,318	4,469
3	Capital Taxes	159	135	115	110	72
4	Income Taxes (Note 1)	283	(994)	(401)	(2,250)	223
5	**Total Cost of Service**	**32,588**	**36,781**	**35,556**	**38,914**	**40,780**

Note 1: Historic years calculated per tax return, Bridge year per tax return projection; Test year based on revenue requirement

HYDRO REMOTES

Mapping OM&A Expenditures to Grouped USofA Accounts for years 2007 - 2009
As at December 31
($000s)

Line No.	Minimum USofA Grouping	Account Numbers	2007	2008	2009
1	Generation - Operation	4510, 4550, 4555	22,543	26,371	25,094
2	Generation - Maintenance	4610, 4635	4,843	5,329	5,803
3	Distribution Expenses - Operation	5085	87	234	191
4	Distribution Expenses- Maintenance	5120, 5125, 5130, 5135, 5175	1,153	1,522	1,457
5	Customer Care (Billing and Collecting)	5310, 5315, 5320, 5335	1,874	1,637	1,800
6	Community Relations	5410, 5415, 5420	413	577	599
7	Administrative and General Expenses	5615, 5625, 5655	877	983	981
8	External Costs	4330	49	83	90
9	**Total OM&A**		**31,840**	**36,736**	**36,016**

COMPARISON OF WAGES AND SALARIES

Year	Representation	Total Pay	Base Pay	Overtime Amount Paid Including Premium	Incentive Pay	Other Allowances	Head Count
2004	MCP	356,776	291,544	-	24,284	40,948	3
	PWU	2,139,135	1,521,901	525,834	-	91,401	23
	SOCIETY	1,011,029	959,671	35,833	-	15,524	11
2004 Total		**3,506,940**	**2,773,116**	**561,667**	**24,284**	**147,873**	**37**
		-					
2005	MCP	382,677	310,720	-	28,150	43,806	3
	PWU	2,360,718	1,735,115	512,891	-	112,711	24
	SOCIETY	678,705	636,276	11,252	-	31,177	10
2005 Total		**3,422,100**	**2,682,111**	**524,144**	**28,150**	**187,695**	**37**
		-					
2006	MCP	478,266	425,572	-	27,743	24,951	4
	PWU	2,287,330	1,774,332	460,047	-	52,951	24
	SOCIETY	687,574	669,309	5,167	-	13,098	7
2006 Total		**3,453,170**	**2,869,214**	**465,213**	**27,743**	**91,000**	**35**
		-					
2007	MCP	634,748	556,455	-	54,650	23,643	5
	PWU	2,357,608	1,902,609	442,800	-	12,199	25
	SOCIETY	766,607	758,850	13,113	-	(5,356)	8
2007 Total		**3,758,964**	**3,217,914**	**455,913**	**54,650**	**30,487**	**38**
2008	MCP	677,212	578,712	-	73,500	25,000	5
	PWU	2,359,140	1,881,300	437,840	-	40,000	24
	SOCIETY	830,500	782,000	35,000	-	13,500	9
2008 Total		**3,866,852**	**3,242,012**	**472,840**	**73,500**	**78,500**	**38**
2009	MCP	697,523	**596,073**		75,700	25,750	5
	PWU	2,632,406	2,099,217	488,556		44,633	26
	SOCIETY	950,510	894,955	40,055		15,500	10
2009 Total		**4,280,439**	**3,590,245**	**528,611**	**75,700**	**85,883**	**41**

HYDRO ONE REMOTE COMMUNITIES INC.

Capital Taxes
Test Year (2009)
Year Ending December 31
($ Thousands)

Line No.	Particulars		2009	
	Capital Taxes			
1	Rate Base (year end):			
2	Gross Plant at Cost	$	51,649	
3	Less Accumulated Depreciation		(24,710)	
4	Net Plant in Service		26,939	
9	Total Working Capital	$	5,615	
10	Rate Base (net plant in service + working capital)	$	32,554	
13	Less Provincial Exemption		(503)	
14	Net Taxable Capital	$	32,051	
15	Capital Tax Rate		0.225	%
16	Total Capital Taxes	$	72	

HYDRO ONE REMOTE COMMUNITIES INC.

Depreciation & Amortization Expenses
Bridge Year (2008) and Test Year (2009)
Year Ending December 31
($000s)

Line No.	Particulars	2008 Provision	2009 Provision
		(b)	(d)
	Depreciation Expenses		
1	Major Fixed Assets	2,473	2,684
2	Minor Fixed Assets	81	78
3	Depreciation on Fixed Assets	2,554	2,762
5	Asset Removal Costs	106	207
6	Losses/(Gains)	(6)	
7	Total Depreciation Expenses	2,654	2,969
	Amortization Expenses		
8	OPEB	329	
9	Environmental Costs	1,335	1,500
12	Total Amortization Expenses	1,664	1,500
13	Total Depreciation & Amortization	4,318	4,469

HYDRO ONE REMOTE COMMUNITIES INC.

Depreciation & Amortization Expenses
Historical Years (2005, 2006 and 2007)
Year Ending December 31
($000s)

Line No.	Particulars	2005 Provision	2006 Provision	2007 Provision
		(b)	(b)	(b)
	Depreciation Expenses			
1	Major Fixed Assets	2,196	2,409.0	2,383.0
2	Minor Fixed Assets	147	141.0	103.0
3	Depreciation on Fixed Assets	2,343	2,550	2,486
5	Asset Removal Costs	122	186.0	204.0
6	Losses/(Gains) on Asset Dispositic	0		
7	Total Depreciation Expenses	2,465	2,736	2,690
	Amortization Expenses			
8	OPEB	329	329	329
9	Environmental Costs	1,238	915	983
12	Total Amortization Expenses	1,567	1,244	1,312
13	Total Depreciation & Amortization	4,032	3,980	4,002

CALCULATION OF UTILITY INCOME TAXES

Attachment A:	Calculation of Utility Income Taxes Test Year (2009)
Attachment B:	Calculation of Capital Cost Allowance Test Year (2009)
Attachment C:	Calculation of Utility Income Taxes Historic Years (2005, 2006, 2007)
Attachment D:	Calculation of Capital Cost Allowance Historic (2005, 2006, 2007) & Bridge Year (2008)

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Utility Income Taxes
Test Year (2009)
Year Ending December 31
($000s)

Line No.	Particulars		2009	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)	$	223	
2	Book to Tax Adjustments:			
3	Other Post Employment Benefits expense		579	
4	Other Post Employment Benefits payments		(382)	
5	Depreciation and amortization		4,469	
6	Capital Cost Allowance		(2,037)	
7	Removal costs		(207)	
8	Environmental costs		(1,500)	
9	Non-deductible meals & entertainment		115	
10	Capitalized interest		(132)	
11	Capitalized overhead costs		(452)	
12				
13		$	453	
14				
15	Regulatory Taxable Income	$	676	
16				
17				
18	Calculation of Utility Income Taxes			
19				
20	Corporate Income Tax Rate		33.00	%
21				
22	Regulatory Income Tax	$	223	
23				
24				
25	Income Tax Rates:			
26				
27	Federal Tax		19.00	%
28	Provincial Tax		14.00	%
29	Total Federal and ON Tax rate		33.00	%

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Capital Cost allowance (CCA)
Test and Bridge Year
2009 & 2008
Year Ending December 31
($000s)

2009 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	16,182.1	200.9	16,383.0	100.4	16,282.6	4%	651.3	15,731.7
2	715.0	80.0	795.0	40.0	755.0	6%	45.3	749.7
3	924.7	9.3	934.0	4.7	929.3	5%	46.5	887.5
6	2,970.9	336.1	3,307.0	168.1	3,138.9	10%	313.9	2,993.1
8	1,061.0	121.0	1,182.0	60.5	1,121.5	20%	224.3	957.7
10	171.9	51.1	223.0	25.5	197.5	30%	59.2	163.8
12	0.8	0.2	1.0	0.1	0.9	100%	0.9	0.1
13	53.2	4.8	58.0	2.4	55.6	10 yrs	1.8	56.2
17	5,188.5	587.5	5,776.0	293.8	5,482.2	8%	438.6	5,337.4
43.1	2.8	0.2	3.0	0.1	2.9	30%	0.9	2.1
45	13.9	0.1	14.0	0.1	13.9	45%	6.3	7.7
47	1,931.2	1,932.8	3,864.0	966.4	2,897.6	8%	231.8	3,632.2
50	27.1	2.9	30.0	1.5	28.5	55%	15.7	14.3
CCA	**29,243.1**	**3,326.9**	**32,570.0**	**1,663.4**	**30,906.6**		**2,036.5**	**30,533.5**

2008 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	16,690.5	162.5	16,853.0	81.2	16,771.8	4%	670.9	16,182.1
2	713.3	45.9	759.2	22.9	736.3	6%	44.2	715.0
3	960.3	12.7	973.0	6.3	966.7	5%	48.3	924.7
6	3,092.6	197.4	3,290.0	98.7	3,191.3	10%	319.1	2,970.9
8	1,243.1	74.0	1,317.0	37.0	1,280.0	20%	256.0	1,061.0
10	128.8	96.2	225.0	48.1	176.9	30%	53.1	171.9
12	8.4	1.7	10.0	0.8	9.2	100%	9.2	0.8
13	5.7	49.3	55.0	24.7	30.4	10 yrs	1.8	53.2
17	5,288.7	336.3	5,625.0	168.1	5,456.9	8%	436.5	5,188.5
43.1	3.7	0.3	4.0	0.2	3.8	30%	1.2	2.8
45	24.4	0.6	25.0	0.3	24.7	45%	11.1	13.9
47	920.4	1,129.6	2,050.0	564.8	1,485.2	8%	118.8	1,931.2
50	59.7	0.3	60.0	0.2	59.8	55%	32.9	27.1
CCA	**29,139.4**	**2,106.8**	**31,246.2**	**1,053.4**	**30,192.8**		**2,003.1**	**29,243.1**

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Utility Income Taxes
Historic Years
2005- 2007
Year Ending December 31
($000s)

Line No.	Particulars		2005		2006		2007	
	Calculation of Federal and ON Taxable Income							
1	Net Income Before Tax (NIBT)	$	189	$	(584)	$	(427)	
2	Required Adjustments to accounting NIBT							
3	Recurring items included in Revenue Requirement (RR):							
4	Other Post Employment Benefit expense		639		812		660	
5	Other Post Employment Benefit payments		(339)		(223)		(237)	
6	Depreciation and amortization		4,032		3,980		4,003	
7	Capital Cost Allowance		(1,958)		(1,935)		(1,966)	
8	Removal costs		(116)		(131)		(204)	
9	Environmental costs paid		(1,238)		(915)		(970)	
10	Hedge loss -net		(663)		-		-	
11	Non-deductible Meals & entertainment		28		100		105	
12	Research & Development ITC (prior year's claim add back)		95		-		-	
13	Capitalized overhead costs deducted		(237)		(179)		(209)	
14								
15		$	243	$	1,509	$	1,182	
16	Deferral accounts not part of RR:							
17	RRRP		492		(3,621)		(1,768)	
18		$	492	$	(3,621)	$	(1,768)	
19	Reversal of accounting adjustments not part of RR:							
20	Contingent liability movement		-		-	#	-	
21	Capitalized interest deductible for tax		(98)		(53)		(113)	
22		$	(98)	$	(53)	$	(113)	
23	Recurring items not part of RR:							
24			-		-		-	
25	Immaterial items not in business plan detail:							
26	Computer application software deducted for accounting		51		2		16	
27	Amortization of financing costs		(12)		(10)		12	
28	Capital tax provision overaccrual (under) vs. return		9		(8)		4	
29	Other		(8)		14		(16)	
30			40		(2)		16	
31								
32	NET Adjustments to Accounting NIBT	$	677	$	(2,167)	$	(683)	
33								
34	Taxable Income Federal and Ontario	$	866	$	(2,751)	$	(1,110)	
35								
36	**Income Tax:**							
37	Federal Income Tax		192		(609)		(246)	
38	LCT -Federal		67		-		-	
39	ON Income Tax		91		(385)		(155)	
40	Total Income Tax and LCT Per Returns		283		(994)		(401)	
41								
42								
43	**ON Capital tax per Return**		145		143		111	
44								
45	Federal Tax		21.00	%	21.00	%	21.00	%
46	Federal Surtax		1.12	%	1.12	%	1.12	%
47	Provincial Tax		14.00	%	14.00	%	14.00	%
48	Corporate Income Tax Rate		36.12	%	36.12	%	36.12	%

See Exhibit C1, Tab 7, Schedule 1 for additional information

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Capital Cost allowance (CCA)
Historic and Bridge Years
2005- 2007
Year Ending December 31
($000s)

2007

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	17,275.4	108.3	17,383.7	54.2	17,329.5	4%	693.2	16,690.5
2	758.8	-	758.8	-	758.8	6%	45.5	713.3
3	13.3	972.0	985.3	486.0	499.3	5%	25.0	960.3
6	3,034.4	380.7	3,415.1	190.4	3,224.7	10%	322.5	3,092.6
8	1,541.6	10.9	1,552.5	5.5	1,547.0	20%	309.4	1,243.1
10	128.6	45.6	174.2	22.8	151.4	30%	45.4	128.8
12	0.7	16.7	17.4	8.4	9.1	100%	9.1	8.4
13	7.5	-	7.5	-	7.5	10 yrs	1.8	5.7
17	4,782.2	926.1	5,708.3	463.1	5,245.3	8%	419.6	5,288.7
43.1	5.2	-	5.2	-	5.2	30%	1.6	3.7
45	12.7	22.4	35.1	11.2	23.9	45%	10.8	24.4
47	515.5	464.7	980.2	232.4	747.9	8%	59.8	920.4
50		82.3	82.3	41.2	41.2	55%	22.6	59.7
CCA	**28,075.9**	**3,029.7**	**31,105.6**	**1,514.9**	**29,590.8**		**1,966.2**	**29,139.4**

2006

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	17,995.2	-	17,995.2	-	17,995.2	4%	719.8	17,275.4
2	807.3	-	807.3	-	807.3	6%	48.4	758.8
3	14.0	-	14.0	-	14.0	5%	0.7	13.3
6	3,324.1	44.9	3,369.0	22.5	3,346.6	10%	334.7	3,034.4
8	1,739.9	166.3	1,906.2	83.2	1,823.0	20%	364.6	1,541.6
10	111.1	59.8	170.9	29.9	141.0	30%	42.3	128.6
12	13.4	1.4	14.8	0.7	14.1	100%	14.1	0.7
13	9.3	-	9.3	-	9.3	10 yrs	1.8	7.5
17	4,159.1	995.7	5,154.8	497.9	4,656.9	8%	372.6	4,782.2
43.1	7.5	-	7.5	-	7.5	30%	2.2	5.2
45	19.2	2.8	22.0	1.4	20.6	45%	9.3	12.7
47	72.2	467.8	540.0	233.9	306.1	8%	24.5	515.5
CCA	**28,272.2**	**1,738.7**	**30,010.9**	**869.4**	**29,141.5**		**1,934.9**	**28,075.9**

2005

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	18,731.9	12.8	18,744.7	6.4	18,737.6	4%	749.5	17,995.2
2	858.8	-	858.8	-	858.8	6%	51.5	807.3
3	14.7	-	14.7	-	14.7	5%	0.7	14.0
6	3,648.8	42.6	3,691.4	23.8	3,672.6	10%	367.3	3,324.1
8	2,087.4	77.7	2,165.1	38.8	2,126.3	20%	425.3	1,739.9
10	128.7	24.7	153.4	12.4	141.1	30%	42.3	111.1
12	2.6	26.8	29.4	13.4	16.0	100%	16.0	13.4
13	-	11.1	11.1	-	11.1	10 yrs	1.8	9.3
17	2,707.9	1,737.3	4,445.2	868.7	3,576.6	8%	286.1	4,159.1
43.1	10.7	-	10.7	-	10.7	30%	3.2	7.5
45	20.9	9.9	30.8	5.0	25.9	45%	11.6	19.2
47	-	74.9	74.9	37.0	36.0	8%	2.7	72.2
CCA	**28,212.4**	**2,017.8**	**30,230.2**	**1,005.4**	**29,227.2**		**1,958.0**	**28,272.2**

2007 HYDRO ONE REMOTE COMMUNITIES INC.

INCOME TAX RETURN

Attachment A: Federal and Ontario Income 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 Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide* (T4012).

Identification

Business Number (BN) 001 87083 6269 RC0001

Corporation's name

002 Hydro One Remote Communities Inc.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** . . . . . 004 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 483 Bay Street, 8th Floor

012 South Tower

City: 015 Toronto

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 M5G 2P5

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)

031 483 Bay Street, 8th Floor

032 South Tower

City: 035 Toronto

Province, territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 M5G 2P5

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.

		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		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		3
Is the corporation claiming any type of losses?	204	X	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		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		———
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177

Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

*** We do not print this schedule.**

Additional information

		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? 282 ____
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Gen & distb electric	285	100.000 %
286		287	%
288		289	%

		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

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300	-1,910,443	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")				C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360		
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)				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		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		B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000	x	Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year	/ 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	400,000	C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C	400,000	x	415 *** ____ D / 11,250	=		E
Reduced business limit (amount C **minus** amount E) (if negative, enter "0")			425		400,000	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 2005 / Number of days in the tax year	/ 366	x 3 %	=	I
Amount H		x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 366	x 5 %	=	J
Amount H		x	Number of days in the tax year in 2007 / Number of days in the tax year	/ 366	x 7 %	=	K
Resource deduction – total of amounts I, J and K					438		L

Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		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")		I

Amount I	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	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 %	=	K
Amount I	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 %	=	K1
Amount I	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 %	=	K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 L
Enter amount L 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)		M
Amount Z1 from Part 9 of Schedule 27	N	
Amount QQ from Part 13 of Schedule 27	O	
Taxable resource income from line 435	P	
Amount used to calculate the credit union deduction (from Schedule 17)	Q	
Total of amounts N, O, P, and Q	▶	R
Amount M **minus** amount R (if negative, enter "0")		S

Amount S	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x 7 %	=	T
Amount S	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	366 / 366	x 8.5 %	=	U
Amount S	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 366	x 9 %	=	U1
Amount S	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	U2

General tax reduction – total of amounts T, U, U1, and U2 V
Enter amount V 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 . . . . ________

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 = ________
________ ▶ ________
________ x 26 2 / 3 % = ________ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ________
Deduct: Corporate surtax from line 600 . . . . ________
Net amount . . . . ________ ▶ ________ 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 . . . . ________ x 1 / 3 ________ 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** ______ A

Corporate surtax calculation

Base amount from line A above . . . . ______ 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) . . . . ______ 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

Part I tax otherwise payable . . . . ______ c
(line A **plus** lines C and D **minus** line F)

______ 6

Total of lines 2 to 6 . . . . ______ 7

Net amount (line 1 **minus** line 7) . . . . ______ 8

Corporate surtax*

Line 8 ______ 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 . . . . ______

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . ______

Net amount . . . . ______ ▶ ______ 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) ______ E

Deduct:

Small business deduction from line 430 . . . . ______ 9

Federal tax abatement . . . . **608** ______

Manufacturing and processing profits deduction from Schedule 27 . . . . **616** ______

Investment corporation deduction . . . . **620** ______

(taxed capital gains **624** ______)

Additional deduction – credit unions from Schedule 17 . . . . **628** ______

Federal foreign non-business income tax credit from Schedule 21 . . . . **632** ______

Federal foreign business income tax credit from Schedule 21 . . . . **636** ______

Resource deduction from line 438 . . . . ______ 10

General tax reduction for CCPCs from amount L . . . . **638** ______

General tax reduction from amount V . . . . **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 ______ ▶ ______ F

Part I tax payable – Line E **minus** line F . . . . ______ G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	
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		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	

Total tax payable 770 ______ 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	
Total credits	890	

B

Refund code 894 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number

918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No X

Certification

I, 950 ALICANDRI (Last name in block letters) 951 VINCENT (First name in block letters) 954 Vice President, Corporate Tax (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-07-28 Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No X

958 BRIAN SOARES Name in block letters

959 (416) 345-6782 Telephone number

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

1 English / Anglais X 2 Français / French ☐

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2008-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accounting practitioner connected* with the corporation? . . . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: 198

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

Has the accounting practitioner expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . 101 1 Yes [X] 2 No [ ]

If *Yes*, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . 102 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . 103 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . 107 1 Yes [ ] 2 No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 1 Yes [ ] 2 No [X]

If *Yes*, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . 109 1 Yes [ ] 2 No [ ]

Canada

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 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			0 A
Add:			
Reserves from financial statements – balance at the end of the year	126	17,678,581	
Subtotal of additions		17,678,581 ▶	17,678,581
Other additions:			
Miscellaneous other additions:			
Subtotal of other additions	199	0 ▶	0
Total additions	500	17,678,581 ▶	17,678,581
Deduct:			
Capital cost allowance from Schedule 8	403	1,910,443	
Reserves from financial statements – balance at the beginning of the year	414	17,678,581	
Subtotal of deductions		19,589,024 ▶	19,589,024
Other deductions:			
Miscellaneous other deductions:			
Total	394		
Subtotal of other deductions	499	0 ▶	0
Total deductions	510	19,589,024 ▶	19,589,024
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			-1,910,443

* For reference purposes only

T2 SCH 1 E (08)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2008-12-31

- This form is used to determine the continuity and use of available losses; to determine the current-year non-capital loss, farm loss, restricted farm loss, and limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that may be applied in a year; and to request a loss carryback to previous years.
- The corporation can choose whether or not to deduct an available loss from income in a tax year. It can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time **and** no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send it by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			-1,910,443
Deduct: (increase a loss)			
Net capital losses deducted in the year (enter as a positive amount)			
Taxable dividends deductible under sections 112, 113, or subsection 138(6)			
Amount of Part VI.1 tax deductible			
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			
Subtotal (if positive, enter "0")			-1,910,443
Deduct: (increase a loss)			
Section 110.5 and/or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			
Subtotal			-1,910,443
Add: (decrease a loss)			
Current-year farm loss			
Current-year non-capital loss (if positive, enter "0")			-1,910,443

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			
Deduct: Non-capital loss expired *	100		
Non-capital losses at the beginning of the tax year	102		
Add: Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110	1,910,443	1,910,443
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Deduct:			
Amount applied against taxable income (enter on line 331 of the T2 return)	130		
Amount applied against taxable dividends subject to Part IV tax	135		
Subtotal			1,910,443
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
Non-capital losses – Closing balance	180		1,910,443

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator . . . . 190 Yes ☐
Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately previous tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year 200
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation 205

Deduct:

Other adjustments (includes adjustments for an acquisition of control) 250
Section 80 – Adjustments for forgiven amounts 240

Add: Subtotal

Current-year capital loss (from the calculation on Schedule 6) 210

Unused non-capital losses that expired in the tax year* . . . . A
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year** . . . . B

Enter amount from line A or B, whichever is less 215
ABILs expired as non-capital loss:
line 215 divided by the inclusion rate*** 75.0000 % 220

Subtotal

Note: If there has been an amalgamation or a wind-up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total at line 220 above.

Deduct: Amount applied against the current-year capital gain (see Note 1) 225

Subtotal

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

Capital losses – Closing balance 280

Note 1
Enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2
On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			
Deduct: Farm loss expired *	300		
Farm losses at the beginning of the tax year	302		
Add: Farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance	380		

* A farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business	485		C
Minus the deductible farm loss:			
$2,500 plus D or E, whichever is less	$ 2,500		
(Amount C above ______ – $2,500) divided by 2 = ______	D		
$ 6,250	E	2,500	F
Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410)			

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired *	400		
Restricted farm losses at the beginning of the tax year	402		
Add: Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
Restricted farm losses – Closing balance	480		

Note
The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			
Deduct: Listed personal property loss expired after seven tax years		500	
Listed personal property losses at the beginning of the tax year		502	
Add: Current-year listed personal property loss (from Schedule 6)		510	
Subtotal			
Deduct:			
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530		
Other adjustments	550		
Subtotal			
Deduct – Request to carry back listed personal property loss to:			
First previous tax year to reduce listed personal property gains	961		
Second previous tax year to reduce listed personal property gains	962		
Third previous tax year to reduce listed personal property gains	963		
Listed personal property losses – Closing balance		580	

Part 7 – Limited partnership losses

Current-year limited partnership losses						
1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 - 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year						
1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year. (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years					
Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	1,910,443			N/A		1,910,443
2007		N/A		N/A			
2006		N/A		N/A			
2005		N/A		N/A			
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			*
Total		1,910,443					1,910,443

Farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A		
2007		N/A		N/A			
2006		N/A		N/A			
2005		N/A		N/A			
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			
2000		N/A		N/A			
1999		N/A		N/A			
1999		N/A		N/A			*
Total							

Restricted farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A	N/A	
2007		N/A		N/A		N/A	
2006		N/A		N/A		N/A	
2005		N/A		N/A		N/A	
2004		N/A		N/A		N/A	
2003		N/A		N/A		N/A	
2002		N/A		N/A		N/A	
2001		N/A		N/A		N/A	
2000		N/A		N/A		N/A	
1999		N/A		N/A		N/A	
1999		N/A		N/A		N/A	*
Total						N/A	

* **This balance expires this year and will not be available next year.**

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 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		16,690,521			0		16,690,521	4	0	0	667,621	16,022,900
2	2		713,293			0		713,293	6	0	0	42,798	670,495
3	3		960,299			0		960,299	5	0	0	48,015	912,284
4	6		3,092,800			0		3,092,800	10	0	0	309,280	2,783,520
5	8		1,243,067			0		1,243,067	20	0	0	248,613	994,454
6	10		128,796			0		128,796	30	0	0	38,639	90,157
7	12		8,336			0		8,336	100	0	0	8,336	
8	13		5,537			0		5,537	N/A	0	0	5,537	
9	17		5,288,688			0		5,288,688	8	0	0	423,095	4,865,593
10	43.1		3,653			0		3,653	30	0	0	1,096	2,557
11	45		24,332			0		24,332	45	0	0	10,949	13,383
12	47		920,410			0		920,410	8	0	0	73,633	846,777
13	50		59,693			0		59,693	55	0	0	32,831	26,862
		Total	29,139,425					29,139,425				1,910,443	27,228,982

* 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.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 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
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	☐	110	115			120
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	275			280

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)

Canadä

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB LT (a/c 453000-260)	5,929,111				5,929,111
2	OPEB Short Term (a/c 358000)	300,000				300,000
3	RRP Rev Deferral (a/c 427191	1,451,572				1,451,572
4	LT-Environ. Liab (a/c452054)	8,191,898				8,191,898
5	Current-Envir. Lia. (452017)	1,806,000				1,806,000
	Reserves from Part 2 of Schedule 13					
	Totals	17,678,581				17,678,581

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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)*
Hydro One Remote Communities Inc.

Ontario Corporations Tax Account No. (MOF): 1800030

Mailing Address
483 Bay Street, 8th Floor
South Tower
Toronto
ON CA M5G 2P5

This Return covers the Taxation Year
Start (year month day): 2008-01-01
End (year month day): 2008-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes — Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 1998-08-18

Registered/Head Office Address
483 Bay Street, 8th Floor
South Tower
Toronto
ON CA M5G 2P5

Ontario Corporation No. (MGS): 1310735

Location of Books and Records
483 Bay Street, 8th Floor
South Tower
Toronto
ON CA M5G 2P5

Canada Revenue Agency Business No.
If applicable, enter: 87083 6269 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
BRIAN SOARES	(416) 345-6782	(416) 345-6978

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

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*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Ministry Use

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s):

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). [X] **No Change**

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
VINCENT ALICANDRI

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): 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired: year ___ month ___ day ___

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[ ]	[X]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.): 89954572

Ontario Employer Health Tax Account no. (Use head office no.):

Specify major business activity: Generation & Distb.

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	-1,910,443
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	-1,910,443

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 ____

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) ____ x 30 100.0000 % Ontario Allocation x 12.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ____ ÷ Total Days: 73 366) = + 29 ____

From 10 (or 20 if applicable) ____ x 30 100.0000 % Ontario Allocation x 14 % x (Days after Dec. 31, 2003: 34 366 ÷ Total Days: 73 366) = + 32 ____

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 ____

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) ☐ Yes ☒ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 ____

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 ____

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 ____

= ____ ▶ 54 ____

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) 55 400,000

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ____ ÷ ** 366) = + 46 ____

400,000 x (Days after Dec. 31, 2003: 34 366 ÷ ** 366) = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) 48 100.0000 % = 45 400,000

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 ____ (Least of 50 , 54 or 45) = 60 ____

* ***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

			Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
Calculation of IDSBC Rate	7 %	x	31	÷ 73	366	= + 89	.
			Days after Dec. 31, 2003		Total Days		
	8.5 %	x	34 366	÷ 73	366	= + 90	8.5000

IDSBC Rate for Taxation Year 89 + 90 = 78 8.5000

Claim From 60 x From 78 8.5000 % = 70

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From 10 (or 20 if applicable) + 80

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)
See schedule			+ 82	
			+ 83	
			+ 84	

Aggregate Taxable Income 80 + 82 + 83 + 84 , etc. = 85

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
320,000	x	31	÷ 73	366	= + 115	
		Days after Dec. 31, 2003		Total Days		
400,000	x	34 366	÷ 73	366	= + 116	400,000

115 + 116 = 400,000 – 114 400,000

(If negative, enter nil) = 86

Number of Days in Taxation Year

			Days after Dec. 31, 2002		Total Days		
Calculation of Specified Rate for Surtax	4.6670 %	x	38 366	÷ 73	366	= + 97	4.6670

From 86 x From 97 4.6670 % = 87

From 87 x From 60 ÷ From 114 400,000 = 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)* 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

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 -1,910,443

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) – From 56

Add: Adjustments for Surtax on Canadian-controlled private corporations + From 122

Subtract: Taxable Income 10 -1,910,443 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

Claim

Number of Days in Taxation Year

143 (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 1.5 % x 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ 73 366 (Total Days) = + 154

143 (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 2 % x 34 366 (Days after Dec. 31, 2003) ÷ 73 366 (Total Days) = + 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

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) No. of Graduates From 6596

Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) + 195 .

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196 .

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 197 .

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

Applies to qualifying R&D expenditures under an eligible research institute contract.

Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198 .

Ontario Production Services Tax Credit (OPSTC) (s.43.10)

Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.

Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 199 .

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)

Applies to qualifying labour expenditures of eligible products for the taxation year.

Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 200 .

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)

Applies to qualifying expenditures in respect of eligible Canadian sound recordings.

Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201 .

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896

Applies to employment of eligible apprentices. 202

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 .

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	
Total Revenue of the corporation	+ 241	

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243	+ 244
			+ 245	+ 246
			+ 247	+ 248

Aggregate Total Assets 240 + 243 + 245 + 247 , etc. = 249

Aggregate Total Revenue 241 + 244 + 246 + 248 , etc. = 250

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 (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	–	277
Subtract: Income Tax	–	From 190
Net CMT Payable (If negative, enter Nil on Page 17.)	=	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
Gross CMT Payable	+	From 276		
Subtract: Foreign Tax Credit for CMT purposes	–	From 277		
If 276 – 277 is negative, enter NIL in 290	=		–	290
Income Tax eligible for CMT Credit			=	300

B.

Income Tax (after deduction of specified credits)	+	From 230
Subtract: CMT credit used to reduce income taxes	–	310
Income Tax	=	320

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	
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	1,000
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	
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	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	1,000
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	1,000
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	1,000

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	.
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	.
Amounts in 360 and 361 (if deducted from assets)	+	440	.
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	.

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	.
Taxable Capital 390 – 460	=	470	1,000 .

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	.
Total Assets (as adjusted)	From 430	.

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		Total Days			
7,500,000	x	Days after Dec. 31, 2004 and before Jan. 1, 2006: 36	÷	73 366	= +	501	.
10,000,000	x	Days after Dec. 31, 2005 and before Jan. 1, 2007: 37	÷	73 366	= +	502	.
12,500,000	x	Days after Dec. 31, 2006 and before Jan. 1, 2008: 38	÷	73 366	= +	504	.
15,000,000	x	Days after Dec. 31, 2007: 39 366	÷	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		Total Days			
0.3 %	x	Days before Jan. 1, 2007: 556	÷	73 366	= +	511	%
0.285 %	x	Days after Dec. 31, 2006 and before Jan. 1, 2009: 557 366	÷	73 366	= +	512	0.2850 %

Capital Tax Rate 511 + 512 = 516 0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 ________ •
– From 503 ________ •
= 471 ________ • x From 30 100.0000 % Ontario Allocation x From 516 0.2850 % 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 1,000

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
See schedule			+ 531	
			+ 532	
			+ 533	

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - - = 540 1,000

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 1,000 ÷ From 540 1,000 x From 503 15,000,000 = 541 15,000,000

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 1,000
– 542 15,000,000
= 471 ______ x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) x 555 366 (Days in taxation year) / * 366 (366 if leap year) = + 523 ______ (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 ______ x From 30 100.0000 % (Ontario Allocation) x From 516 0.2850 % (Capital Tax Rate) - - - - = + 561 ______

– Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - – From 995 ______

= 562 ______

Capital Tax - - - - 562 ______ x 555 366 (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 ______

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - – 546 ______

Capital Tax 543 – 546 *(amount cannot be negative)* - - - - = 550 ______

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 -1,910,443

Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	1,910,443
Federal cumulative eligible capital deduction	+ 602	
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	17,678,581
Federal allowable reserves. Balance end of year	+ 605	
Ontario non-allowable reserves. Balance end of year	+ 606	17,678,581
Ontario allowable reserves. Balance beginning of year	+ 607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	
Federal resource allowance *(Refer to Guide)*	+ 609	
Federal depletion allowance	+ 610	
Federal foreign exploration and development expenses	+ 611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

612 ______ x 5 / 12.5 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days: 73 366) = + 633 ______

612 ______ x 5 / 14 x (Days after Dec. 31, 2003: 34 366 ÷ Total Days: 73 366) = + 634 ______

Total add-back amount for Management fees, etc. 633 + 634 = ______	+ 613	
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+ 615	
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 = 37,267,605 ▶ 640 37,267,605

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	1,910,443
Ontario cumulative eligible capital deduction	+ 651	
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	17,678,581
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	17,678,581
Federal allowable reserves. Balance beginning of year	+ 656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	
Ontario depletion allowance	+ 658	
Ontario resource allowance *(Refer to Guide)*	+ 659	
Ontario current cost adjustment *(Attach schedule)*	+ 661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	

Subtotal of deductions for this page 650 to 659 + 661 + 675 — 681 37,267,605

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	-1,910,443
Total of Additions on page 14	From =	640	37,267,605
Sub Total of deductions on page 14	From =	681	37,267,605

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 = 37,267,605 ▶ 680 37,267,605

Net income (loss) for Ontario Purposes 600 + 640 – 680 - - - = 690 -1,910,443

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 1,910,443	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703 1,910,443	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) 1,910,443	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 1,910,443	836	846	859	879
Total	829 1,910,443	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 1,910,443	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 1,910,443	929	939	949

Summary

Income Tax	+ From 230 or 320	
Corporate Minimum Tax	+ From 280	
Capital Tax	+ From 550	
Premium Tax	+ From 590	
Total Tax Payable	= 950	
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	
If payment due	Enclosed * 990	
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)*

VINCENT ALICANDRI

Title

Vice President, Corporate Tax

Full Residence Address

c/o 483 Bay Street
South Tower, 8th floor
Toronto
ON CA M5G 2P5

Signature

Date

2008-07-28

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Non-Capital Loss Continuity Workchart – Ontario

Non-capital losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A	1,910,443			N/A	1,910,443
2007		N/A		N/A		
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		*
Total		1,910,443				1,910,443

Farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2007		N/A		N/A		
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
1999		N/A		N/A		
1999		N/A		N/A		*
Total						

Restricted farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2007		N/A		N/A		
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
1999		N/A		N/A		
1999		N/A		N/A		*
Total						

* **This balance expires this year and will not be available next year.**

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
Hydro One Remote Communities Inc.	1800030	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	16,690,521			0	16,690,521		16,690,521	4	0	0	667,621	16,022,900
2	713,293			0	713,293		713,293	6	0	0	42,798	670,495
3	960,299			0	960,299		960,299	5	0	0	48,015	912,284
6	3,092,800			0	3,092,800		3,092,800	10	0	0	309,280	2,783,520
8	1,243,067			0	1,243,067		1,243,067	20	0	0	248,613	994,454
10	128,796			0	128,796		128,796	30	0	0	38,639	90,157
12	8,336			0	8,336		8,336	100	0	0	8,336	
13	5,537			0	5,537		5,537	N/A	0	0	5,537	
17	5,288,688			0	5,288,688		5,288,688	8	0	0	423,095	4,865,593
See schedule	1,008,088				1,008,088		1,008,088				118,509	889,579
Totals	29,139,425				29,139,425		29,139,425				1,910,443	27,228,982

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Capital Cost Allowance

Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2008-12-31

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
43.1	3,653			0	3,653		3,653	30	0	0	1,096	2,557
45	24,332			0	24,332		24,332	45	0	0	10,949	13,383
47	920,410			0	920,410		920,410	8	0	0	73,633	846,777
50	59,693			0	59,693		59,693	55	0	0	32,831	26,862
Totals	1,008,088				1,008,088		1,008,088				118,509	889,579

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
Hydro One Remote Communities Inc.	1800030	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 $
Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 – Other reserves

Description	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from **D** plus the amount from **E** should be entered in 607 of the CT23.
The amount from **F** should be entered in 654 of the CT23.

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
OPEB LT (a/c 453000-260)	5,929,111					5,929,111
OPEB Short Term (a/c 358000)	300,000					300,000
RRP Rev Deferral (a/c 427191	1,451,572					1,451,572
See schedule	9,997,898					9,997,898
Reserves from Part 2						
Totals	17,678,581					17,678,581
	Enter in box 653 *of the CT23*					*Enter in box* 606 *of the CT23*

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2008-12-31

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
LT-Environ. Liab (a/c452054)	8,191,898					8,191,898
Current-Envir. Lia. (452017)	1,806,000					1,806,000
Totals	9,997,898					9,997,898

2006 BOARD APPROVED VS. 2006 ACTUALS OM&A VARIANCE EXPLANATIONS

The following table compares 2006 actual costs versus 2006 Board approved costs for OM&A. The 2006 Board-approved amounts were based on 2004 actuals.

OM&A Cost Categories	**2006 Actuals** ($000s)	**2006 EDR Board Approved** ($000s) (Based on 2004 Actuals)	**Variance** ($000s)
Generation - Operation	22,068	20,398	1,670
Generation – Maintenance	4,353	4,460	(107)
Distribution – Operation	150	64	86
Distribution - Maintenance	1,391	991	399
Customer Care	4,394	1,680	2,714
Community Relations	214	334	(120)
Shared Services & Other Costs	1,026	578	448
External Costs	64	-	64
Total OM&A	33,660	28,505	5,154

Remotes' actual OM&A costs were $33,659 thousand compared to $28,505 thousand approved by the Board in the RP-2005-0020/EB-2005-0497 Decision with Reasons, an increase of $5,154 thousand. The majority of this differential comes from increases in Generation Operations and Customer Care, but also from increases in Distribution Operations, Distribution Maintenance, Shared Services and Other Costs, offset by decreases in Generation Maintenance, Community Relations and External Costs. There is also an element of inflation included in the variance due to the comparison of 2006 actuals with 2006 Board approved amounts based on 2004 actuals.

Customer Care expenses were higher than plan due to higher bad debt costs ($2,758K) relating to a change in Management's understanding of INAC's policy with respect to guaranteeing payment for outstanding arrears related to essential services in First Nation communities. This is discussed in more detail in Exhibit C1, Tab 2, Schedule 4.

Generation Operations were higher than OEB approved primarily due to higher fuel costs ($703K) and higher generation expense ($967K) related to emergency engine, auxiliary and operations maintenance required to maintain reliability.

Shared Services and Other Costs were $448 thousand higher relating to a capitalized overhead credit and a change in corporate allocation methodology. The capitalized overhead credit ($111K) reflects lower capital expenditures than planned associated with the delay in the generation upgrade in Sandy Lake and other recoverable capital work, and Management's decision to redirect resources to operations maintenance work required to maintain reliability in Sandy Lake and Deer Lake. The increase relating to the change in common corporate cost allocation ($433K) relates to the impact on Remotes caused by the adoption of a new methodology to allocate common costs among Hydro One companies. In 2005, Hydro One Networks commissioned a study by R. J. Rudden Associates ("Rudden") to determine a methodology to allocate common costs among the business entities, including Remotes, using the common services. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received and was approved in subsequent Hydro One Networks Distribution and Transmission rate cases. Remotes 2006 actual expenditures are based on this methodology, however 2006 Board approved costs are based on the former allocation methodology.

Community Relations expenses were lower than approved ($120K) due to a delay in implementation of the Customer Demand Management Program.

RATE BASE

1.0 INTRODUCTION

This exhibit provides the forecast of Remote's rate base for the 2009 test year and provides a detailed description of each of the rate base components.

In accordance with the 2006 Electricity Distribution Rate Handbook ("Handbook"), the rate base underlying the test year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross plant in service minus accumulated depreciation and contributed capital[1]. Working capital is calculated using the formula as described in the Section 5.4 of 2006 Electricity Distribution Rate Handbook.

2.0 UTILITY RATE BASE

Utility rate base for Remotes for the test year is filed at Exhibit D2, Tab 1, Schedule 1.
Remotes' forecast rate base for the test year is $30,326 thousand.

Table 1
Remotes Rate Base ($000s)

Description	**Test 2009**
Gross Plant	48,319
Accumulated Depreciation	(23,608)
Net Plant	**24,711**
Cash Working Capital	5,615
Utility Rate Base	**30,326**

[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

Note: The change in rate base reflected above lowers the return on rate base by $52 ``thousand (lowering it to $1,720 thousand from $1,772 thousand shown in original evidence (Exhibit B1, Tab 1, Schedule 1)). This is reflected in the revised revenue requirement evidence.

The mid-year gross plant balance reflects the capital expenditure programs forecast for the bridge and test years. These programs are described in detail in the company's written `evidence at Exhibits D1, Tab 2, Schedule 1 and in the supporting schedules filed at Exhibit D2, Tab 2, Schedule 2. The justification for capital projects in excess of $230 thousand (1% of 2007 Net Fixed Assets) are filed at Exhibit D2, Tab 2, Schedule 3.

The net plant component of the 2006 rate base approved in the RP-2005-0020/EB-2005-0497 was $22,118 thousand. Continuity schedules are provided in Exhibit D2, Tab 3.

Table 2
Continuity of Fixed Assets Summary ($000s)

Description	Historic			Bridge	Test
	2005	2006	2007	2008	2009
Opening Gross Asset Balance	37,224	39,156	41,247	43,390	46,146
In-Service Additions	2,590	2,460	3,188	3,262	4.904
Retirements	(655)	(369)	(1,045)	(457)	(558)
Transfers	(2)	-	-	(49)	
Closing Gross Asset Balance	39,156	41,247	43,390	46,146	50,492
Mid Year Gross Asset Balance	38,190	40,202	42,319	44,768	48,319

In-service additions reflect the placing in-service of Remotes' capital programs. These programs are described in detail at Exhibit D1, Tab 2, Schedule 1.

Retirements in 2005 include the retirement of a Sandy Lake generator which was retired due to failure and need to replace. 2007 retirements included fully amortized meters ($373K) and minor fixed assets ($581K) as well as normal asset retirement.

The nature and composition of Remotes' assets are described in detail in Exhibit D1, Tab 1, Schedule 2.

3.0 WORKING CAPITAL

Working capital is at 15% of eligible OM&A expenses per the *2006 Electricity Distribution Rate Handbook*. A detailed calculation is found in Exhibit D2, Tab 4, Schedule 1.

Table 3

Working Capital Calculation	($000s)
Total Eligible OM&A Expenses	37,432
Working Capital Allowance @ 15.0%	5,615

REMOTES' DISTRIBUTION AND GENERATION ASSETS

1.0 INTRODUCTION

At December 31, 2007, Remotes managed net fixed assets of $22,981 thousand to provide the safe and reliable generation and delivery of electricity to 3,332 customers in 20 remote communities across Ontario's far north.

In each community, the generating assets consist of a fenced site property, including a generator building and storage outbuildings; diesel generator sets, comprised of diesel engines, and alternating current generators; electrical switch gear with engine controls, breakers and step up transformers; a Programmable Logic Controller (PLC) including a Supervisory Control and Data Acquisition (SCADA) System; an engine cooling system including piping and external radiators; an engine exhaust system comprised of manifolds, silencers and exhaust stacks; a diesel fuel system including multiple bulk fuel tanks, transfer pumps, piping, automated valves, day tanks, fuel coolers, meters and an off-load kiosk; and a building auxiliary system including secondary heating system (ventilation system), communications, lighting and station service and compressed air.

The major distribution system components include: conductors, switches, transformers, insulators, reactors, capacitors, connecting hardware, associated protection and control equipment, foundations, grounding systems and revenue meters.

2.0 KEY CHARACTERISTICS OF THE GENERATION SYSTEM

Due to the lack of grid connection, Remotes is a generator of electricity to meet its obligations under section 29 of the *Electricity Act, 1998*. Diesel generation is currently the prime source of electricity within the communities. Remotes also owns and operates two run-of-the-river mini-hydro electric generating facilities and has four demonstration project windmills. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost effective technology. Remotes believes that First Nations must be involved in renewable energy projects in their communities, and is working with local First Nations and with private sector developers to assist in developing renewable energy resources. Remotes would enter into power purchase agreements based on the avoided cost of diesel fuel to support these projects.

There are presently 55 diesel generators in service, ranging in size from 85kW to 1100kW. The stations are designed to maximize fuel efficiency and also to provide some generation redundancy in the event of engine failure. Most stations have three generators, sized to meet community load at different times of the day and season. Automated operation ensures that each generator is dispatched to match community load, thereby maximizing fuel efficiency. The stations are designed so that failure of any single unit does not jeopardize supply. The largest unit is sized to meet the peak load in the community, and equals the output of the two smaller units. Remotes' had $13.2M in net generating assets at the end of 2007.

3.0 KEY CHARACTERISTICS OF THE DISTRIBUTION SYSTEM

Remotes operates 18 isolated distribution systems to serve the 20 communities. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. Because the communities are far from each other, the distribution systems are isolated, distinct and stand-alone and are planned for and operated as separate distribution systems. These distribution systems operate at distribution voltages ranging from 4.8 kV to 25 kV.

The fixed distribution assets in service include approximately 210 kilometers of line and 1,145 transformers distributed throughout the system, which are used for voltage transformation. Billing meters are used to measure energy consumption at customer supply points.

The distribution systems are designed and operated to industry standards. The distribution systems are relatively new, originally built in the 1970s and 1980s. The systems are radial in design, with very little redundancy in supplies to customers, which is consistent with rural utilities. Due to this configuration, most component failures require immediate repair to restore service. Remotes had $4.1M in net distribution assets at the end of 2007.

4.0 KEY CHARACTERISTICS OF FACILITIES

Remotes has a Service Centre in Thunder Bay, Generating Station buildings in 18 communities and associated outbuildings such as storage sheds, and staff houses in 14 communities. Repairs and capital replacements are normally undertaken when facilities deteriorate and include items such as rebuilding roofs, building garages to house vehicles in the communities, and improvements to staff houses required to meet health and safety standards.

CAPITAL PROGRAMS

1.0 INTRODUCTION

Under the Electrification Agreements with INAC, INAC funds new generation and distribution capital within First Nation communities served by Remotes. Remotes does not record the value of this contributed capital and does not depreciate these capital contributions.

Until 2005, Remotes paid for a small portion of the costs of generation upgrades in First Nation communities. Remotes no longer pays any part of the cost for generation upgrades, except for specific projects that were initiated and agreed to prior to 2005. Remotes depreciates the cost of the capital it contributes to these legacy upgrade projects. In non-First Nation communities, the provincial government funded the original capital costs of the plants. Remotes is responsible for replacement costs at these sites.

Remotes' ongoing capital expenditures relate primarily to asset and equipment replacement required in order to deliver electricity safely and reliably to the 20 communities in its service territory. Remotes' invests in assets when these expenditures are required to replace end of life assets, meet new standards or to improve the overall operations and efficiency of the plant when an upgrade is not planned.

An overview of Remotes' proposed capital investments for the historic, bridge and test years is provided in Table 1 below

Table 1
ANNUAL CAPITAL INVESTMENTS
($000s)

	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
Generation	2,088	1,169	2,744	2,031	3,758
Distribution	243	391	80	252	641
Facilities	563	683	831	679	639
MFA	73	117	100	115	100
Total	2,967	2,360	3,755	3,077	5,138

Remotes capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year. The overhead capitalization rate for 2009 is 6.4%.

Capitalized overheads include CCF&S costs that are not purely OM&A related. The following table shows capitalized overheads, and the overhead capitalization rates for the Historical, Bridge and Test Years.

Table 2
Overhead Capitalization
Historical, Bridge and Test Year

	Historic			Bridge	Test
	2005	**2006**	**2007**	**2008**	**2009**
Total capitalized overheads ($000s)	237	179	209	237	452
Capitalized overhead rate (%)	7.6	6.4	5.7	5.6	6.4

Remotes' capital programs have three main categories: generation capital, which includes generation related investments; distribution related investments; and investments in facilities. Remotes' plans its capital investments in accordance with customer requirements and good utility practice, in order to maintain safety and reliability, and to ensure that it is compliant with regulatory requirements and operational standards. Remotes is planning key investments in generation capital designed to improve overall environmental performance, and to improve the fuel efficiency of its generating stations.

2.0 GENERATION CAPITAL PROGRAMS

The major components of Remotes generation capital programs include Engine Overhauls and Replacements; Emergency System Breakdowns; Design Construction and Asset Management Projects; and Renewable Energy Partnerships.

2.1 Engine Overhauls and Replacements

Diesel engines and their components are subject to deterioration that will eventually lead to a decline in equipment performance and reliability, increased environmental and safety risks, and failures. Each Remotes station has between two and four generators, which are programmed to follow the community load in order to maximize fuel efficiency. Engine overhauls are scheduled when the operating hours for each engine reaches 20,000 hours for 1800 RPM units and 40,000 hours for 1200 RPM units. When an older engine is expected to reach 60,000 hours in the next operating year, the engine is replaced with a new unit that incorporates current emission reduction technology and improved fuel efficiency. Engines are also replaced when the cost of a major overhaul is estimated to be greater than the cost of a new engine.

The frequency and timing of major engine overhauls and component replacements are planned in accordance with manufacturer's procedures and are based on the hours an engine has run. The forecast for this capital work changes based on actual engine run times which are determined by actual community loads and which engine is picked to operate by the automated engine control system.

2.2 Emergency System Breakdowns

The Emergency System Breakdown program provides for replacements related to catastrophic failures in the distribution systems or generation systems and their auxiliary systems. These costs are generally associated with plant fires, catastrophic failures of major plant equipment, and major storms. Catastrophic failure rates vary, based on external factors such as weather and station or forest fires and on the failures of major plant equipment. While preventive maintenance can control and reduce failure rates, equipment failures may still occur.

2.3 Design, Construction and Asset Management Programs

Design, Construction and Asset Management Programs include a variety of projects to replace or improve diesel stations, tank farms, secondary heat systems, the Programmable Logic Controller (PLC) and Supervisory Control and Data Acquisition (SCADA) systems and generation protection systems. Normally these improvements are undertaken when customer load increases and new station capacity is required. In these cases, INAC funds required improvements, in accordance with Remotes station standards. The station standards encompass energy efficiency requirements, including engine efficiency, auxiliary system efficiency (variable frequency drives in pumps and radiators for example), bays for vehicles to reduce the requirement for block heaters, and the use of waste heat from generation operations to heat the station and a staff house.

In non-First Nation's communities, where INAC does not fund capital, Remotes plans to replace existing stations in order to ensure that these stations meet current environmental and safety standards. These efficiency standards have led to a reduction in the use of diesel fuel by 4% per kWh generated where they have been implemented. Remotes plans to spend $419 thousand to replace the stations in Oba and Biscotasing in 2009.

When community load growth does not justify a capital upgrade, and equipment ages or cannot be modified to meet current standards, Remotes is responsible for replacing generating stations, tank farms and auxiliary equipment. In 2009, Remotes plans improvements to the tank farm in Big Trout Lake ($280K). The removal of the entire fuel transfer system is planned. The improvements to the tank farm are required to reduce customer outages due to pump suction problems in cold weather, to add protection from spills and to improve platforms to offer higher safety conditions.

Remotes also plans a zero emissions project to test catalytic reactor technology at its Armstrong station ($358K). This technology would reduce station emissions to less than those of a single stage natural gas turbine. Remotes plans to test this technology in order to develop possible changes to its station guidelines.

Remotes' PLC and SCADA systems were originally installed between 1998 and 2000. Vendors no longer support the existing equipment and software. Cable internet is now available in all of the First Nation communities offering faster real-time station monitoring. The PLC and SCADA systems are integral to Remotes operations. The automation of Remotes generators to follow community load has resulted in 10% improvements to fuel efficiency. Real-time monitoring of the station permits Remotes to identify station failures such as outages or fuel spills. Remotes plans to replace its PLC and SCADA systems in 2009 ($280K).

The 2006 and 2007 year-over-year variances in generation capital relates to a legacy agreement with INAC to cost share the Deer Lake upgrade ($624K) and to the capital replacement of auxiliary equipment for radiator replacements in Kingfisher Lake and Weagamow ($249K) and increased expenditure related to the tank farm ($428K) required to meet current standards.

Generation variances between the bridge and test year are related to a focus on recoverable work in 2008, an increase in the forecast engine hours in 2009 ($643K), improvements to the tank farm in Big Trout Lake that are required to meet current standards ($280K), replacement of the secondary heat systems in Sachigo Lake and Kingfisher Lake ($191K), station improvements to achieve zero emissions at the Armstrong Station ($358K), . and replacement of the generating stations in the road sites ($419K). These investments are partly offset by the completion of the radiator replacement program ($129K) and the completion in 2008 of upgrade in Sandy Lake, where a cost sharing agreement is in place with INAC ($430K).

2.4 Renewable Energy Partnerships

Expenditures related to renewable energy partnerships have been reclassified as OM&A and are discussed in Exhibit C1, Tab 2, Schedule 2. The related Investment Justification Document, G8 in Exhibit D2, Tab 2, Schedule 3 has been deleted.

3.0 DISTRIBUTION CAPITAL PROJECTS

3.1 Minor Storm Damage and Damage Claims

Minor Storm Damage involves the replacement of plant units damaged by lightning, wind and other storm-related impacts and is distinguished from Emergency System Breakdown program by the scale of damage. If storm damage required the replacement of a significant portion of the distribution system, the Emergency System Breakdown program would be accessed. Costs related to minor storm damage, and service outages related to storm damage, are expected to fall in 2010 and beyond, with the implementation of cyclical forestry clearing over 2008 and 2009

Damage Claims cover the replacement of plant units resulting from third party damages that are not fully recoverable from the third party. These instances can occur, for example, when an uninsured driver runs into a utility pole. Damage claims may result in a partial recovery from the responsible party and/or Remotes needing to expense the portion of work that is not a capital refurbishment.

3.2 Distribution System Improvements

Distribution System Improvements include planned improvements and component replacements required to maintain the operation of distribution lines and associated facilities. This program also includes small external demand requests for Joint Use work in association with Bell and local First Nation attachments. Line inspections will identify conditions that require capital work to bring the Distribution System up to current standards, as prescribed by Section 4.4 of the *Distribution System Code* and by the Electrical Safety Authority under O.Reg 22/04 made under the *Electricity Act, 1998*.

The lower distribution capital in 2007 from 2006 relates primarily to distribution system improvements in Webequie in 2006 ($286K) and the focus in 2007 on recoverable work. Distribution variances between bridge and test year reflect increased costs for improvements associated with asset condition assessments ($365K) and initial investments in smart meter technologies ($32K).

4.0 FACILITIES CAPITAL

Remotes has an on-going program to maintain, refurbish and repair facilities such as staff houses, outbuildings and the Thunder Bay service centre. Repairs are normally undertaken when facilities deteriorate and include items such as rebuilding roofs, building garages to house vehicles in the communities, and improvements to staff houses required to meet health and safety standards.

Increased investments in Facilities in 2007 and 2008 compared to other years relate to staff houses including facilities in Big Trout Lake, Hillsport and Fort Severn.

5.0 MINOR FIXED ASSETS

Minor fixed assets include relatively small purchases of computers, equipment and office furniture.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The interest rate used for construction work in progress (CWIP), which is referred to as Allowance for Funds Used During Construction (AFUDC) reflects the Board's decision in EB-2006-0117, effective November 28, 2006. This decision prescribed that the interest rate to use for CWIP, effective May 1, 2006, would be the Scotia Capital All-Corporates Mid-Term Average Weighted Bond Yield, as published on the Bank of Canada website and updated quarterly. As a result the 2008 Bridge and 2009 Test years reflects a forecast of the prescribed CWIP rate (as described in Exhibit A, Tab 13, Schedule 2), respectively, while the historical years reflect CWIP at Remotes' previously approved embedded cost of debt.

Table 1
Allowance for Funds Used During Construction

Year	AFUDC Rate %	($000s)
2005	6.80	98
2006	6.39	53.7
2007	4.95	113.5
2008	5.29	91.3
2009	5.59	132.3

REMOTE COMMUNITIES INC.
Statement of Utility Rate Base
Forecast Year (2009)
Year Ending December 31
($000s)

Line No.	Particulars		2009
	Electric Utility Plant		
1	Gross plant at cost	$	48,319
2	Less: accumulated depreciation		(23,608)
3	Net plant in service	$	24,711
4	Cash working capital	$	5,615
5	Total rate base	$	30,326

COMPARISON OF CAPITAL EXPENDITURES - HISTORIC, BRIDGE AND TEST YEARS

	$000s				
	2005	**2006**	**2007**	**2008**	**2009**
Generation					
Planned Capital Replacement of Diesel Engines & Aux Equipment	1,094	531	884	904	1,418
Emergency System Breakdowns inc. Temp Units	952	410	498	534	539
Upgrade projects	(46)	(120)	1,174	430	0
DCAM Programs	89	347	187	162	1,801
				0	0
Total "Generation"	**2,088**	**1,169**	**2,744**	**2,031**	**3,758**
Distribution					
Metering, Minor Storm Damage, Damage Claims, Small Ext Demand Re	111	46	41	127	161
Fixed Price Layouts, New Customer Connections & Service Upgrades	75	0	(20)	0	0
Distribution System Improvements	56	345	59	125	481
Total " Distribution"	**243**	**391**	**80**	**252**	**641**
Facilities					
Planned Capital Call-Up/Replace Powerhouse, Staffhouse, Outbuildings & Service Centre	563	683	831	679	639
Total "Facilities"	**563**	**683**	**831**	**679**	**639**
Minor Fixed Assets	73	117	100	115	100
Overall Total	**73**	**117**	**100**	**115**	**100**
TOTAL REMOTES CAPITAL	**2,967**	**2,360**	**3,755**	**3,077**	**5,138**

LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $230K TEST YEAR - 2009

*($000s)

1.0 GENERATION CAPITAL (EXHIBIT D1, TAB 1, SCHEDULE 2)

G1	Replacement of Diesel Engines	1,418
G2	Emergency System Breakdown	539
G3	Protection Upgrade	273
G4	SCADA and PLC Upgrades	280
G5	Road Site Replacements	419
G6	Armstrong Zero Emissions	358
G7	Big Trout Lake Tank Farm Improvements	280

Summary

Total Generation projects/programs listed above	3,567
Generation projects/programs less than $230K	191
Total Generation capital (per Exhibit D1-3-1)	3,758

2.0 DISTRIBUTION Capital (Exhibit D1, Tab 1, Schedule 2)

D1	Distribution System Improvements	481

Summary

Total Distribution projects/programs listed above	481
Distribution projects/programs less than $230K	160
Total Distribution capital (per Exhibit D1-3-1)	641

3.0 FACILITIES CAPITAL (EXHIBIT D1, TAB 1, SCHEDULE 2)

F1	Planned Facility Improvements	639

Summary

Total Facilities projects/programs listed above	639
Facilities projects/programs less than $230K	0
Total Facilities capital (per Exhibit D1-3-1)	639

4.0 MINOR FIXED ASSETS (EXHIBIT D1, TAB 1, SCHEDULE 2)

Minor Fixed Assets	100
Total Capital Expenditures	**$5,417**

JUSTIFICATION FOR PROGRAMS/PROJECTS IN EXCESS OF 230K

G1	Replacement of Diesel Engines	1,418
G2	Emergency System Breakdown	539
G3	Protection Upgrade	273
G4	SCADA and PLC Upgrades	280
G5	Road Site Replacements	419
G6	Armstrong Zero Emissions	358
G7	Big Trout Lake Tank Farm Improvements	280
D1	Distribution System Improvements	481
F1	Planned Facility Improvements	639

Remote Communities Capital Program - 2009

Investment Category: GENERATION – Planned Capital/Replacement of Diesel Engines - RMGCA0041

Description: Major Overhauls/Replacements

Major Overhauls/Replacements

Major diesel engine component replacement based on engine manufacturer's preventative maintenance procedures on 60 diesel engines. These overhauls are scheduled to occur when engine hours reach 20,000 for 1800 RPM and 40,000 for 1200 RPM engines.

Major component replacement is carried out on site in the Remote Communities.

The diesel engines range in size from 85kW to 1,000kW. The diesel plants have between 2 and 4 engines per community. The engine run hours are controlled to minimize fuel consumption. Therefore the size, RPM and location of engines due for major overhaul varies from year to year. Where the cost of a major overhaul is estimated to be less than the new replacement cost, the engine is replaced. Key cost factors associated with overhauls are size, RPM and location. The number of engine run hours determines the time of overhaul, in accordance with manufacturer's recommended parts replacement. The PLC program selects the most fuel-efficient engine(s) to run at any given time based on expected engine fuel efficiency for the community load. Annual engine hours are projected based on load forecasts, however actual engine run time varies with actual community loads. In 2008, a program to replace older engine models, projected to accumulate 60,000 hours in the next operating year, with new units that incorporate current emission reduction technology and have improved fuel efficiency, is being initiated. This will be carried forward in the 2009, 2010 and 2011 capital plan.

Year 2009 engine overhauls

Unit	Rating (kW)	Model
Biscotasing A	100	Cat 3304B
Fort Severn A	600	Cat 3512 (1200rpm)
Kasabonika C	600	Cat 3412
Kingfisher C	250	Detroit
Lansdowne A	250	Cat 3406B
Wapekeka A	820	Cat 3508B

Unit
Bearskin B
Deer Lake B
Sachigo A
Weagamow A

Budget/Cash Flow

Year	$
2005	1,089,920
2006	535,167
2007	635,242
2008	774,994
2009	1,417,537

Justification Details (check one)

□ Safety
☑ Customer/Reliability
□ Environment
□ Regulatory
□ Business Efficiency
□ Other

Financial Evaluation Results/Benefits to be achieved/delivered:

This program covers major component replacement on the diesel generating sets to extend/renew life of the generators.

Need and Planning Assumptions:

This work involves major overhauls on diesel units in accordance with recommended maintenance cycle provided by the diesel generator manufacturer based on engine hours .

If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code. N/A	
Alternatives Considered: Do nothing and replace unit upon failure	
Risk Assessment of not doing the job: Customer outages due to catastrophic failure of diesel generating units	
Customer Impact: Customer outages	
Prepared by	Jim Kirkpatrick
Approved by	Rick Rhodes
Date	May 20, 2008

Remote Communities Capital Program - 2009

Investment Category: Emergency System Breakdown - RMGCA0045

Description:
Year 2009 –
The amount of catastrophic failure varies with the following key factors:
- following manufacture's maintenance procedures
- weather (for distribution system)
- fire (station and forest)

This program also include major failures of secondary heating systems in Wapekeka and Kingfisher Lake.
A major failure such as station fire would cost several million dollars and take more than one year to restore. A minor generator, diesel motor, station transformer or tank farm failure would cost between $50k and $500k.
In 2003 we had several minor failures $780k(Sandy Lake B Unit, Webequie A Unit and Kingfisher A Unit)
In 2004 we had several minor failures $ 835k Big Trout Lake C Unit, Weagamow A Unit, Sandy Lake B Unit and Gull Bay B Unit)
In 2005 we had several minor failures $ 952k (Remaining Big Trout Lake C Unit work, Sandy Lake C unit and Sandy Lake C unit alternator, and Armstrong A Unit)
In 2006 the number of minor failures was reduced to the expected(budget) level $ 410k
In 2007 emergency breakdowns again were maintained within the budget level

☑ Business Case Summary Required

Budget/Cash Flow

Year	$
2005	951,791
2006	410,191
2007	498,457
2008	534,375
2009	538,988

Justification Details (check one)
- ☐ Safety
- ☑ Customer/Reliability
- ☐ Environment
- ☐ Regulatory
- ☐ Business Efficiency
- ☐ Other

Financial Evaluation Results/Benefits to be achieved/delivered:
This program covers major unforeseen plant replacement in the diesel generating stations or distribution system. These costs are associated with major storms (eg. Ice or wind), plant fires and catastrophic failures of major plant equipment.

Need and Planning Assumptions:
Unable to predict a major failure by location or by type of difficulty.

If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code.
Any change in engine type will meet all current applicable legislation (eg. MOE Certificate of Approval – Air, Noise, Emissions).

Alternatives Considered:
Not responding to emergency breakdowns would result in increased customer outages, system reliability and capability.

Risk Assessment of not doing the job:
Regulator and customer dissatisfaction will increase.

Customer Impact:
Extended outages for customers.

Prepared by	Jim Kirkpatrick
Approved by	Rick Rhodes

Remote Communities Capital Program – 2009

Investment Category: GENERATION – Protection Upgrades - RMGCA60

Description:
This project will improve fault clearing in the generating station and on the distribution system.
It is a continuation of the design work commenced in 2007 with a roll-out to stations for implementation in 2008 and 2009. The project is expected to consist of installed relay(s) and current and potential transformers that allow better fault discrimination.

☑ Business Case Summary Required

Cash Flow

Year	$
2008	269,963
2009	273,135
2010	270,481

Justification Details (check one)

☑ Safety
☑ Customer/Reliability
□ Environment
□ Regulatory
□ Business Efficiency
□ Other

Financial Evaluation Results/Benefits to be achieved/delivered:
This project is required to improve the clearing time of faults and improve the coordination of fault clearing in our stations and on our distribution system.
This protection will enable instantaneous clearing of faults on the distribution feeder.

Need and Planning Assumptions:
A fault study has been conducted on our system that has indicated areas for improvement.

If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code.
The protections will meet all current applicable legislation.

Alternatives Considered:
Do nothing.

Risk Assessment of not doing the job:
Public safety will be improved and the customer outages will be reduced.

Customer Impact:
Improvement in system reliability and reduced outages.

Prepared by	Ralph Falcioni/Jim Kirkpatrick
Approved by	Rick Rhodes
Date	

Remote Communities Capital Program – 2009	
Investment Category: SCADA & PLC Upgrades - RMGCA60XX	
Description: The original PLC's were installed in 1998 to 2000. Subsequent stations have received more powerful systems, and the software and hardware has evolved greatly. Although communications were originally dial-up connections, cable Internet is now available in all FN communities, offering faster real-time station monitoring. Existing equipment is no longer supported by vendors. ☑ Business Case Summary Required	
Cash Flow Year $ 2008 110,700 2009 279,975 2010 169,635 Total Project Cost $560,310	
Justification Details (check one) □ Safety ☑ Customer/Reliability □ Environment □ Regulatory ☑Business Efficiency □ Other	
Financial Evaluation Results/Benefits to be achieved/delivered: More information received from the stations in a real-time mode can only improve the troubleshooting aspect of station failures. In time it will improve our service to restore power during station failures.	
Need and Planning Assumptions: The benefits promised by the PLC system and SCADA have been proven over the years, and become indispensable. This project will update the programme to the station guidelines.	
If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code. Not applicable.	
Alternatives Considered: Status quo, not improving the systems until a station upgrade occurs.	
Risk Assessment of not doing the job: Stations will not be consistent with one another as we allow upgrades to improve individual sites. Rather than 18 standard systems, we will end up with 18 diverse designs, which leads to other issues. Equipment and software support is no longer available.	
Customer Impact: Improvement in system reliability and reduced outages.	
Prepared by	Ralph Falcioni
Approved by	Rick Rhodes
Date	2008 April

Remote Communities Capital Program – 2009	
Investment Category: Road Site Replacements – RMGCA60XX	
Description: The diesel stations at the four road sites are totally funded by the province. The communities are not subject to load growth, being stagnant due to the nature of their citizens (old railroad town turned to seasonal occupancy generally). The stations are small and equipment is aging. Technical improvements have occurred over a number of years, but can no longer be accommodated in the present structure. The gap between the Station Standards is significant. Project encompasses replacements to all of the stations, with a two-year plan (first year is planning, second is construction). A common design principle will be developed in 2008, probably a modular design, that can then be implemented in subsequent years. The costs for each year would be divided among two sites (Oba, Biscotasing, Hillsport, Sultan). ☑ Business Case Summary Required	
<u>Year</u> <u>$</u> 2008 27,038 2009 418,677 (net of $100,000 in removal costs) 2010 444,769 (net of $100,000 in removal costs) 2011 445,698 (net of $100,000 in removal costs) 2012 173,059 (net of $100,000 in removal costs) Total Project Cost $ 1,509,241 over five years net of $400,000 in removal costs	
Justification Details (check one) ☑ Safety ☑ Customer/Reliability ☑ Environment	□ Regulatory ☑ Business Efficiency □ Other
Financial Evaluation Results/Benefits to be achieved/delivered: All aspects of our business are improved with a replacement of these stations: safety, environment, reliability, maintenance costs, etc. No design has been developed yet, but modular/interchangeable design has been used in Northern BC with success.	
Need and Planning Assumptions: Cost estimates must be developed in the design phase to be sure station costs are reasonable.	
If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code. The upgraded facility will meet all current applicable legislation (eg. MOE Certificate of Approval – Air, Noise, Emissions, TSSA).	
Alternatives Considered: Status quo.	
Risk Assessment of not doing the job: Status quo means that stations will continue to age, more maintenance costs, less fuel economy, higher environmental risks, etc.	
Customer Impact: Improvement in system reliability and reduced outages.	

Prepared by	Ralph Falcioni
Approved by	Rick Rhodes
Date	2008 April

Remote Communities Capital Program - 2009	
Investment Category: Armstrong Zero Emissions - RMGCA60XX	
Description: Catalytic reactor technology exists to provide station emissions to less than that of a single stage natural gas turbine. Specialized equipment has been tested at Toromont. Using the SCR and urea injection for one unit in Armstrong as a trial site will develop the changes to the station guidelines. ☑ Business Case Summary Required	
Budget/Cash Flow Year: 2009 — $: 358,368	
Justification Details (check one) □ Safety □ Customer/Reliability ☑ Environment □ Regulatory □ Business Efficiency □ Other	
Financial Evaluation Results/Benefits to be achieved/delivered: This project would be a project to provide the required changes to our station guidelines.	
Need and Planning Assumptions: Armstrong is a road site close to Thunder Bay to allow minimal travel expenses (air), yet large enough to accommodate additional equipment.	
If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code. The installation will meet all current applicable legislation, and offer much improved emission data.	
Alternatives Considered: Near zero emissions is the goal, and other options would be wind or hydroelectric generation (which still require some diesel backup). Newer engines with lower emissions closes the gap but will not yield near zero emissions for some time to come.	
Risk Assessment of not doing the job: System reductions are required each year so if a zero emissions strategy was adopted, great steps would be made by tackling the larger gensets first.	
Customer Impact: See Risk Assessment	
Prepared by	Ralph Falcioni
Approved by	Rick Rhodes
Date	2008 April

Remote Communities Capital Program – 2009

Investment Category: Big Trout Lake Tank Farm Improvements – RMGCA5803

Description:
The project involves removal of the entire fuel transfer system from bulk tanks to day tanks, including suction transfer pumps. New equipment includes submersible pumps, automated valves, piping, day tanks, start/stop controls, high level detection, and improvements to tank platforms.
Project will improve fuel transfer operations from bulk tanks to day tanks with the installation of submersible pumps in the fuel tanks, and automated valves on transfer system. Day tanks are replaced with new tanks, complete with electronic level controls and additional high level protection devices.

☑ Business Case Summary Required

Budget/Cash Flow

Year	$
2009	279,975

Justification Details (check one)

□ Safety
☑ Customer/Reliability
☑ Environment
□ Regulatory
□ Business Efficiency
□ Other

Financial Evaluation Results/Benefits to be achieved/delivered:
Customer outages due to pump suction problems will be eliminated in cold weather. Additional electronic controls add protection from spills. Platform improvements offer higher safety conditions.

Need and Planning Assumptions:
The new fuel transfer system follows the recommended station guidelines for new plants.

If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code.

Installation would conform to current TSSA regulations.

Alternatives Considered:
Station improvements might be postponed until the next upgrade but the time frame is at least five years under current situation.

Risk Assessment of not doing the job:
Continued fuel transfer problems during the cold weather lead to customer outages.

Customer Impact:
See Risk Assessment

Prepared by	Ralph Falcioni
Approved by	Rick Rhodes
Date	2008 April

Remote Communities Capital Program - 2009

Investment Category: Distribution System Improvements – Planned (RMDCA0021)

Description:
Distribution system improvements include planned improvements and component (plant unit/meter) replacement required to maintain the operation of distribution lines and associated facilities. Also includes small external demand requests for Joint Use work in association with (eg.) Bell attachments.

□ Business Case Summary Required

Budget/Cash Flow

Year	$
2005	56,149
2006	344,572
2007	58,984
2008	318,075
2009	480,896

Justification Details (check one)

□ Safety	□ Regulatory
x Customer/Reliability	□ Business Efficiency
□ Environment	□ Other

Financial Evaluation Results/Benefits to be achieved/delivered:

Need and Planning Assumptions:
Line inspections will identify conditions that will require capital work required to bring the Distribution System up to current standards.
(NOTE: 2009 increase is to allow for Sandy Lake feeder improvements at airport)

If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code.
Work required to keep the distribution system in a standard operating condition is a Utility responsibility prescribed by Section 4.4 of the Distribution System Code, and ESA Reg. 22/04.

Alternatives Considered:
Leave conditions intact until as long as immediate safety/operation is not compromised.

Risk Assessment of not doing the job:
Deferred plant unit replacement may not provide for service reliability or public safety

Prepared by:
Stewart Sears

Approved by:
Rick Rhodes

Date:

Remote Communities Capital Program - 2009	
Investment Category: Planned Facility Improvements	
Description: Refurbishment/replacement of major building components eg. roof, auxiliary equipment such as heating systems at staff houses, station buildings and service centre, to supplement minor maintenance of these facilities. Projects for 2009 include the following: • Kingfisher staff house • Kasabonika truck garage • Deer Lake truck garage ☑ Business Case Summary Required	
Budget/Cash Flow Year — $ 2005 — 562,670 (included roof replacement at service centre) 2006 — 682,799 2007 — 830,773 2008 — 811,125 2009 — 638,791	
Justification Details (check one) □ Safety □ Customer/Reliability □ Environment □ Regulatory ☑ Business Efficiency □ Other	
Financial Evaluation Results/Benefits to be achieved/delivered: This work will extend staff house service life, incorporate energy efficient designs and provide for compliance with current environmental codes, applicable building codes and station designs. Truck garages in communities where station is remote from the airport are required for secure storage.	
Need and Planning Assumptions: Refurbishment of existing staff house facilities required to extend their use for 10-15 years. Garage construction will be phased in at 3 locations over the business plan period.	
If any legislation, regulation or code requires that the expenditure be made, list the section reference of the applicable legislation, regulation or code. Changes to fuel supply of staff heating systems to comply with TSSA Fuel Oil Ontario Regulation 213/01 and CSA B139-00.	
Alternatives Considered: Utilize existing staff house facilities with minor maintenance repairs.	
Risk Assessment of not doing the job: Facility condition deteriorates to a point where it becomes unavailable for use without major repair/replacement.	
Customer Impact: N/A	
Prepared by	Jim Kirkpatrick
Approved by	Rick Rhodes
Date	May 20, 2008

HYDRO ONE REMOTE COMMUNITIES INC

Mapping In-Service Additions to Grouped USofA Accounts for years 2007 - 2009
As at December 31
($000s)

Line No.	Minimum USoA Grouping	Account Numbers	2007	2008	2009
1	Land and Buildings	1805, 1806, 1808, 1810, 1905, 1906	-	2	7
2	TS Primary Above 50	1815	-	-	-
3	Distribution Station Equipment	1820	-	-	-
4	Poles, Wires	1830, 1835, 1840, 1845	143	91	315
5	Line Transformers	1850	136	37	38
6	Services and Meters	1855, 1860	(4)	71	87
7	General Plant	1908, 1910	1,210	394	659
8	Equipment	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960	82	107	84
9	IT Assets	1920, 1925	19	8	16
10	Generation Plant	1615, 1620, 1650, 1665, 1670, 1675, 1680, 1685, 1970, 1975, 1980, 2005	1,603	2,553	3,698
11	Smart Meters		-	-	-
12	**Total In-Service Assets**		**3,188**	**3,262**	**4,904**

HYDRO ONE REMOTE COMMUNITIES INC.
Continuity of Property, Plant and Equipment
Year Ending December 31
Historical (2005, 2006, 2007), Bridge (2008) & Test (2009) Years
Total - Gross Balances
($000s)

Fixed Assets

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2005	37,224	2,590	(655)		(2)	39,156	38,190
2	2006	39,156	2,460	(369)			41,247	40,202
3	2007	41,247	3,188	(1,045)			43,390	42,319
Bridge								
4	2008	43,390	3,262	(457)	-	(49)	46,146	44,768
Test								
5	2009	46,146	4,904	(558)	-		50,492	48,319

HYDRO ONE REMOTE COMMUNITIES INC.
Continuity Accumulated Depreciation
Year Ending December 31
Historical (2005, 2006, 2007), Bridge (2008) & Test (2009) Years
Total - Gross Balances
($000s)

Fixed Assets

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Historic									
1	2005	15,101	2,343	(655)			(1)	16,787	15,944
2	2006	16,787	2,547	(366)				18,968	17,878
3	2007	18,968	2,533	(1,045)	-	(47)		20,409	19,689
Bridge									
4	2008	20,409	2,554	(457)	-	-		22,506	21,458
Test									
5	2009	22,506	2,762	(558)	-	-		24,710	23,608

HYDRO ONE REMOTE COMMUNITIES INC.
Continuity of Property, Plant and Equipment - Construction Work in Progress
Year Ending December 31
Historical (2005, 2006, 2007), Bridge (2008) & Test (2009) Years
Total - Gross Balances
($000s)

Fixed Assets

Line No.	Year	Opening Balance (a)	Capital Expenditures (b)	Transfers to Plant (c)	Other Adjustments (d)	Closing Balance (e)
Historic						
1	2005	1,629	2,967	(2,590)	2	2,008
2	2006	2,008	2,360	(2,460)	12	1,920
3	2007	1,920	3,755	(3,188)	31	2,518
Bridge						
4	2008	2,518	3,077	(3,261)		2,334
Test						
5	2009	2,334	5,138	(4,905)	-	2,567

HYDRO ONE REMOTE COMMUNITIES INC.

Statement of Working Capital
Test Year (2009)
($000s)

Line No.	Particulars		2009
	OM&A Expenses		
1	Generation	$	32,291
2	Distribution		1,666
3	Billing and Collecting		1,805
4	Community Relations		599
5	Administrative & General		981
6	External Costs		90
7	Total Eligible OM&A	$	37,432
8	Working Capital Factor		15%
9	**Working Capital Allowance**	**$**	**5,615**

2006 BOARD APPROVED VS. 2006 ACTUALS CAPITAL VARIANCE EXPLANATIONS

1.0 CAPITAL EXPENDITURES

Remotes' ongoing capital expenditures relate primarily to asset and equipment replacement. Remotes also invests in assets when these expenditures are required to meet new standards or to improve the overall operations and efficiency of the plant when an upgrade is not planned.

Capital Expenditures ($ thousand)	**2006 Actuals** ($ thousand)	**2006 Board Approved**[1] ($ thousand) (Based on 2004 Actuals)	**Variance** ($ thousand)
Distribution	391	231	160
General	683	223	460
Generation	1,169	1,664	(495)
Minor Fixed Assets	117	42	75
Total	2,360	2,160	200

Minor fixed assets include computer (IT) equipment, office furniture and equipment, service equipment and transport and work equipment.

Remotes' capital expenditures in 2006 were $2,360 thousand compared to $2,160 thousand approved by the Board for 2006 (based on 2004 actuals).

Primary factors for higher spending in 2006 (actual vs Board approved) than 2004 were distribution improvements in the community of Webequie ($234K) and rebuilding the

[1] Remotes used the EDR model for its 2006 filing. No project specific capital approvals were given as capital spending was expected to be in the normal range and no specific large projects had been identified

staff house in Sachigo Lake and Bearskin Lake garage, which have reached their end of life ($460K). These increases were partly offset by lower emergency breakdowns ($425K).

2.0 RATE BASE

Rate Base Component ($ Thousands)	2006 Actuals	2006 Board Approved (Based on 2004 Actuals)	Variance
Gross Plant	$41,247	$36,357	$ 4,890
Accumulated Depreciation	(18,968)	(14,239)	(4,729)
Net Plant	**22,279**	**22,118**	**$161**
Cash Working Capital1	4,276	4,276	0
Total Rate Base	26,555	$26,393	$161

Remotes does not calculate actual cash working capital, thus the 2006 approved amount was used for illustrative purposes.

Total rate base was $162 thousand above the board approved amount, a variance of less than 1%.

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for 2006 that would have met the criteria for Tier 1 approval. The figures given are for 2004 actual net capital spending, the historical year on which the Board's approvals were based.

REVENUE REQUIREMENT

1.0 SUMMARY OF REVENUE REQUIREMENT

Remotes follows standard regulatory practice and has calculated revenue requirement consistent with the principles of the 2006 Electricity Distribution Rate Handbook as follows:

Table 1
($000s)

OM&A	36,016	Exhibit C1, Tab 2, Schedule1
Depreciation and Amortization	4,469	Exhibit C1, Tab 6, Schedule 1
Capital Taxes	72	Exhibit C2, Tab 4, Schedule 1
Income Taxes	223	Exhibit C2, Tab 6, Schedule 1, Att A
Return on Capital (100% debt)	1,720	Exhibit B1, Tab 1, Schedule 1
Total Revenue Requirement	$42,500	Exhibit E2, Tab 1, Schedule 1
Less Revenue Offset	(27,845)	Exhibit G1, Tab 1, Schedule 3
Rate Revenue Requirement	$14,655	Exhibit E2, Tab 1, Schedule 1

The resultant Total Revenue Requirement of $42,500 thousand is the amount required by Remotes to ensure the most appropriate, cost-effective solution to respond to corporate objectives mainly related to public and employee safety, electricity market and regulatory requirements. The rate revenue requirement of $14,655 thousand represents the amount to be funded by Remotes customers.

2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

2.1 OM&A Expense

	($000s)
Generation	$30,897
Distribution	1,648
Customer Care	1,800
Community Relations	599
Shared Services and Other Costs	981
External Costs	90
Total OM&A	**$36,016**

2.2 Depreciation and Amortization Expense

Depreciation	$2,762
Amortization	1,707
Total Expense	**$4,469**

2.3 Capital Taxes

Capital Tax	72
Total Capital Taxes	**$72**

2.4 Payments in Lieu of Corporate Income Taxes

Income Before Payments in Lieu of Corporate Income Taxes	$676
Tax Rate	33.0%
Total Payments in Lieu of Corporate Income Taxes	**$223**[1]

2.5 Return on Capital

Return on Capital (100% debt)	$1,720

[1] Calculated on the basis of regulatory taxes payable, as per 2006 Electricity Distribution Rate Handbook; see Exhibit C2, Tab 6, Schedule 1 for detailed calculation.

3.0 REVENUE REQUIREMENT – COMPARISON OF YEAR 2006 TO YEAR 2009

Table 2 below compares, by element, the Year 2006 approved Revenue Requirement (as per RP-2005-0020/EB-2005-0378) against the Year 2009 proposed Revenue Requirement.

Table 2
Comparison of Revenue Requirements: 2006 vs. 2009 ($000s)

Line No	Description	Year 2006 OEB Approved	Year 2009	Difference
1	OM&A	28,505	36,016	7,511
2	Depreciation	4,750	4,469	(281)
3	Capital Tax	152	72	(80)
3	Income Taxes	99	223	124
4	Return	2,045	1,720	(325)
5	**Total Revenue Requirement**	**35,551**	**42,500**	**6,949**
6	Revenue Offset	(21,097)	(27,845)	(6,748)
7	Rate Revenue Requirement	**$14,454**	**$14,655**	**201**

There are a number of key operational and financial factors contributing to the increased revenue requirement. The increase in Total Revenue Requirement is largely attributable to the increase in OM&A costs ($7,511K) and Income Taxes partly offset by lower depreciation, capital tax and a return on rate base reflective of the lower cost of debt (7.75% in 2006 vs. 5.68% in 2009).

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Revenue Requirement
Year Ending December 31, 2009
($000s)

Line No.	Particulars		2009
	Cost of Service		
1	Operating, maintenance & administrative	$	36,016
2	Depreciation & amortization		4,469
3	Capital taxes		72
4	Income taxes		223
5	Cost of service excluding return (Note 1)	$	40,780
6	Return on capital		1,720
7	Service revenue requirement	$	42,500
8	Less Revenue Offset		(27,845)
9	Total Revenue Requirement		$ 14,655

Note 1: Per Exhibit C2, Tab1, Schedule 1

OTHER REVENUES

1.0 OVERVIEW

Remotes' Other Revenues include late payment and specific service charges which are regulated by the Board, and revenues from external work. External work is not regulated by the Board. The costing of external work is determined on the basis of cost causality with estimates calculated in the same way as internal work using the standard labor rates (resource rate), equipment rates, material surcharge, and overhead rates (see Exhibit C1, Tab 6, Schedule 1 for a description of Costing of Work).

2.0 LATE PAYMENT AND SPECIFIC SERVICE CHARGES

Remotes applies a late payment charge to customer account balances remaining 21 days after the issuance of the bill. The charge is 1.5% and is compounded monthly, resulting in a charge of 19.56% per annum. The charge is applied to outstanding balances, except GST, 23 days after the billing date. This is a standard business practice for overdue accounts. Remotes does not propose to change its current Late Payment Charge, as this charge complies with all legislative and regulatory requirements.

Remotes also charges for other specific services that it performs as part of its utility business. Remotes does not propose to change the rates for these charges, as they are consistent with charges levied by other Ontario electricity distributors. Table 1, below shows Remotes' charges for specific services and late payment fees.

Table 1

Late Payment and Specific Service Charges

($000s)

Service Description	**Charge**
Late Payment Charge	1.5% per month
Dispute Meter Test	$30.00
Collection/Disconnection/Load Limiter/Reconnection (if in community)	$65.00
Account Set-Up Charge	$30.00
Arrears Certificate	$15.00
NSF Cheque Charge	$15.00 + bank charges

Table 2

Revenues from Late Payment and Service Charges

($000s)

Historic Years			**Bridge**	**Test**
2005	**2006**	**2007**	**2008**	**2009**
1,055	1,217	1,037	507	506

Significant variances in revenues between 2007 and 2008 and 2009 relate to reduced arrears, and the implementation of negotiated payment plans in certain communities. Descriptions of Remotes' actions to reduce arrears is discussed in more detail in Exhibit C1, Tab 2, Schedule 4.

3.0 EXTERNAL WORK

Remotes performs a small amount of unregulated external work. There are three main areas of work: assistance to the Electricity Safety Authority to facilitate inspections of Remotes' distribution systems and of customer installations; maintenance of street lights and First Nation owned generating equipment in Remotes service territory; and assessments of the Independent Power Authority generating stations (First Nation owned and operated generating stations in remote communities Remotes does not serve). These assessments are undertaken in cooperation with INAC and the Nishnawbe Aski Development Fund. These assessments identify operational risks and efficiency measures that could be undertaken by INAC or the local First Nation. Revenues from external work are shown in Table 3, below.

Table 3
Revenues from External, Unregulated Work
($000s)

Historic Years			Bridge	Test
2005	**2006**	**2007**	**2008**	**2009**
102	50	130	96	103

RURAL AND REMOTE RATE PROTECTION VARIANCE ACCOUNT

1.0 INTRODUCTION

Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve breakeven results of operations after the inclusion of PILs. Any excess or deficiency in remote rate protection revenues necessary to lead to breakeven results of operations is added to, or drawn from, the Rural and Remote Rate Protection (RRRP) Variance Account, which was established in 2002 for this purpose.

As part of the approval of Remotes' 2005 submission, the Board permitted Remotes to retain the balance in the RRRP account in order to stabilize customer rates. Over the past three years, due primarily to increases in the cost of diesel fuel ($5M) and the need to create an adequate provision for bad debts ($4M), Remotes has drawn down the balance in the RRRP variance account. The account is now in a deficit position. Remotes is proposing the recovery of the balance in this account in 2009.

($000s)

	Historic		Bridge	Test
Rural and Remote Rate Protection Variance Account (USofA 2320)	2006	2007	2008 Projected	2009 Estimated
	(3,219)	**(1,464)**	**4,013**	**0**

PROPOSED CUSTOMER RATES

1.0 INTRODUCTION

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the *Ontario Energy Board Act, 1998*. O. Reg. 442/01 requires the Board to calculate the amount of Rate Protection for these customers. In view of this legislative requirement, Remotes did not undertake a cost allocation study as required by Board guidelines prior to filing this application. A cost allocation study requires substantial effort and would have provided no benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation.

Remotes is proposing to increase rates to customers in its service territory by the average increase for grid connected customers. In order to determine proposed increases for Remote Community customers for 2009, Remotes calculated the average distribution increases approved by the Board in 2008. Approximately one-third of distributors rebased their rates, while the other two-thirds followed the 2nd Generation IRM. The average distribution revenue increase for distributors who rebased rates was approximately 11.4%. The 2nd Generation IRM increase was approximately 1.0%. Therefore, the average distribution increase was 4.4% (0.33 x 11.4% + 0.67 x 1.0%).

In 2006, the Board approved an inclining block rate structure for Year Round Residential (R2), Residential Seasonal (R4), General Service Single Phase (G1) and General Service Three-Phase (G3) customers. The inclining blocks were designed such that customers with very high usage would be subject to a price signal to encourage conservation. Remotes is proposing to set, after a period of time, the third and final block of usage to reflect actual costs, and is therefore proposing an initial 25% increase to rates for the final block. The schedule for subsequent increases will be determined later.

The current and proposed rates for each customer class are shown in Table 1.

Table 1

Current and Proposed Remote Community Rates

Year-Round Residential (R2)

	Existing Rates	Proposed 2009	Increase
Service Charge	$16.45	$17.17	4.4%
Block 1 *First 1,000 kWh*	$0.0775	$0.0809	4.4%
Block 2 *Next 1,500 kWh*	$0.1033	$0.1078	4.4%
Block 3 *All additional (Over 2,500 kWh)*	$0.1300	$0.1625	25%

Residential Seasonal (R4)			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$27.80	$29.02	4.4%
Block 1 *First 1,000 kWh*	$0.0775	$0.0809	4.4%
Block 2 *Next 1,500 kWh*	$0.1033	$0.1078	4.4%
Block 3 *All additional (over 2,500 kWh)*	$0.1300	$0.1625	25%

General Service Single Phase (G1)			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$27.95	$29.18	4.4%
Block 1 *First 6,000 kWh*	$0.0868	$0.0906	4.4%
Block 2 *First 7,000 kWh*	$0.1150	$0.1201	4.4%
Block 3 *All additional (over 13,000 kWh)*	$0.1300	$0.1625	25%

General Service Three Phase (G3)			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$35.00	$36.54	4.4%
Block 1 *First 25,000 kWh*	$0.0868	$0.0906	4.4%
Block 2 *Next 15,000 kWh*	$0.1150	$0.1201	4.4%
Block 3 *All Additional (Over 40,000 kWh)*	$0.1300	$0.1625	25%

Street Lighting			
	Existing Rates	**Proposed 2009**	**Increase**
kWh	$0.0860	$0.0898	4.4%

Standard A Residential Road Rail			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$0.00	$0.00	0%
Block 1 *First 250 kWh*	$0.5096	$0.5320	4.4%
Block 2	$0.5822	$0.6078	4.4%

Standard A Residential Air Access

	Existing Rates	**Proposed Rates**	**Increase**
Service Charge	$0.00	$0.00	0%
Block 1 *First 250 kWh*	$0.7691	$0.8029	4.4%
Block 2	$0.8418	$0.8788	4.4%

Standard A General Service Road Rail			
	Existing Rates	**Proposed Rates**	**Increase**
Service Charge	0.00	0.00	0%
kWh	$0.5822	$0.6078	4.4%

Standard A General Service Air Access			
	Existing Rates	**Proposed Rates**	**Increase**
Service Charge	0.00	0.00	0%
kWh	$0.8418	$0.8788	4.4%

RURAL AND REMOTE RATE PROTECTION REQUIREMENT

1.0 INTRODUCTION

Remotes has two broad categories of customers, Standard A or government customers whose rates were historically set above cost, and those Residential and General Service customers who benefit from Rural and Remote Rate Protection. These two categories are set out in O. Reg. 442/01, the regulation under the *Ontario Energy Board Act, 1998* that establishes the rules for Rural and Remote Rate Protection (RRRP). Most of Remotes' customers pay rates that are subsidized by RRRP and are set well below the per kWh cost to serve from diesel fuel.

The revenues to fund the RRRP program are derived from charges to all electricity users in the grid-connected part of the Province. A charge of $0.0010/kWh is added to the Wholesale Market Service charge of $0.0052/kWh by distributors and collected from all customers. The IESO bills all market participants for the $0.0010/kWh charge on all electricity transmitted through the IESO-controlled grid, generating approximately $150 million per year of RRRP revenues. Under current Board-approved processes, Hydro One Networks receives the total amount of RRRP from the IESO and maintains a variance account to track over or under collection of RRRP to meet the program's requirements. Hydro One Networks distributes Remotes' OEB approved share of RRRP revenues in equal installments throughout the year.

RRRP transfers account for over half of Hydro One Remotes' revenues each year. RRRP for customers in Remotes' service area is currently set at $21,097 thousand per year.

Sections 4(2) and 4(3) of Regulation 442/01 set out the rules for determining the level of rural and remote rate protection for Remotes' customers as follows:

The Board shall calculate the amount by which Hydro One Remote Communities Inc.'s forecasted revenue requirement for the year as approved by the Board exceeds Hydro One Remote Communities Inc.'s forecasted consumer revenues for the year, as approved by the Board.

2.0 LOAD AND REVENUE FORECAST

The revenue usage/load forecast is compiled using a combined and comprehensive approach. Remotes' tracks actual historical data on energy usage by community, customer class, and time period. This historical data provides the baseline starting point for forecasting revenue usage/KWH sold. Adjustments are made to this baseline data on a go forward basis for items such as average usage growth, expected customer changes and impacts of conservation programs. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads. Historical averages, growth patterns, and seasonal adjustments also impact the forecast.

Revenues are calculated based on the rate class usage characteristics and the applicable rate schedules.

Table 1 below shows the 2009 load forecast by customer class.

Table 1

2009 Load Forecast by Customer Class

Customer Class	**Average # of Customers**	**Block 1 mwh**	**Block 2 mwh**	**Block 3 mwh**	**Total**
Residential Year Round (R2)	2,561	22,864	9,077	1,961	33,902
Residential Seasonal (R4)	139	213	22	3	237
General Service Single Phase	291	4,792	589	101	5,482
General Service Three Phase	28	3,410	246	56	3,712
Std A Residential Road/Rail	18	54	15	N/A	69
Std A Residential Air Access	114	342	1,088		1,430
Std A General Service Road/Rail	26	603	N/A	N/A	603
Std A General Service Air Access	299	9,025			9,025
Street Lights	5	185	N/A	N/A	185
Total	3,480	41,487	11,037	2,120	54,644

Table 2 shows the Revenue forecast by customer class, and by block usage at current rates.

Table 2

Revenue Forecast at Current Rates

($000s)

Customer Class	Service Charge	Block 1 kWh	Block 2 kWh	Block 3 kWh	Total kWh	Total Service and kWh
Residential Year Round (R2)	500.0	1,797.5	937.7	254.9	2,990.1	3,490.1
Residential Seasonal (R4)	46.4	16.5	2.2	0.4	19.1	65.5
General Service Single Phase	97.4	415.9	67.7	13.1	496.7	594.1
General Service Three Phase	11.6	296.0	28.3	7.2	331.6	343.1
Std A Residential Road/Rail		27.5	8.7		36.2	36.2
Std A Residential Air Access		262.6	916.2		1,178.9	1,178.9
Std A General Service Road/Rail		351.2			351.2	351.2
Std A General Service Air Access		7,597.3			7,597.3	7,597.3
Street Lights	N/A	15.9	N/A	N/A	15.9	15.9
Total	655.4	10,780.5	1,960.9	275.6	13,017.1	13,672.4

Table 3 shows the revenue forecast by customer class and by block usage at proposed 2009 rates.

Table 3

Revenue Forecast at 2009 Proposed Rates

($000s)

Customer Class	Service Charge	Block 1 kWh	Block 2 kWh	Block 3 kWh	Total kWh	Total Service and kWh
Residential Year Round (R2)	521.9	1,849.7	978.5	318.6	3,146.8	3,668.7
Residential Seasonal (R4)	48.4	17.2	2.3	0.4	20.0	68.4
General Service Single Phase	101.7	434.1	70.7	16.3	521.2	622.9
General Service Three Phase	12.1	308.9	29.6	9.1	347.6	359.7
Std A Residential Road/Rail		28.7	9.1		37.8	37.8
Std A Residential Air Access		274.1	956.5		1,230.7	1,230.7
Std A General Service Road/Rail		366.7			366.7	366.7
Std A General Service Air Access		7,931.3			7,931.3	7,931.3
Street Lights	N/A	16.6	N/A	N/A	16.6	16.6
Total	684.1	11,227.4	2,046.8	344.5	13,618.7	14,302.8

The forecast customer revenues are based on annual usage, whereas the proposed 2009 rates will be implemented May 1, 2009. Therefore, the increased customer revenues from rates will be less than the 2009 annual amount shown in Table 3. Based on the seasonality of load, Remotes estimates that the increase will apply to 59.198% of 2009 load.

Table 4

Rate Implementation

($000s)

Total Proposed rates	14,302.8
Total current rates	13,672.4
Increase	630.4
Pro-rated (59.198%)	373.2
Total 2009 forecast customer revenues	14,045.5

3.0 FORECAST RRRP REQUIREMENT

Table 5

Forecasted RRRP Requirement

($000s)

Item		
2009 Revenue Requirement		$42,500
	Disposition RRRP Variance Account	4,013
Less:	2009 Revenue from Customer Rates	(14,046)
	Other Revenues	(609)
RRRP Level for 2009		**$31,858**

CUSTOMER BILL IMPACTS

1.0 INTRODUCTION

The impacts of the proposed changes are shown in Tables 1 to 4 below.

2.0 RESIDENTIAL YEAR ROUND (R2)

The Year-Round Residential classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as year-round residential, all of the following criteria must be met:

(1) Occupants must state that this is their principal residence for the purposes of the *Income Tax Act*;
(2) The occupant must live in this residence for at least eight months of the year;
(3) The address of this residence must appear on the occupant's electrical bill, driver's license, credit card invoice, etc;
(4) Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for that purpose at the address of this residence.

Table 1 below, shows the percentage change in monthly bills of the proposed 2009 rates compared to the current 2008 rates. The analysis is based on the total bill, including a monthly service charge. The average monthly usage for Residential year-round customers in 2007 was 1,157 kWh per month. An average customer would pay $115.00 per month based on the proposed rates, compared to $110.17 at current rates, or an increase of 4.4%.

Table 1

Bill Impacts for Residential (R2) Customers

RESIDENTIAL YEAR ROUND (R2)			
Scenario (kWh)	**Existing Bill**	**Proposed Bill**	**Percentage Change**
100	$24.20	$25.26	4.4%
250	$35.83	$37.40	4.4%
500	$55.20	$57.62	4.4%
750	$74.58	$77.85	4.4%
1000	$93.95	$98.07	4.4%
1500	$145.60	$151.97	4.4%
2000	$197.25	$205.87	4.4%
2500	$248.90	$259.77	4.4%
3000	$313.90	$341.02	8.6%

3.0 RESIDENTIAL SEASONAL (R4)

This classification is comprised of cottages, chalets and camps or any other residential service not meeting the residential year round criteria. Table 2 gives a comparison of current versus proposed rates for Residential Seasonal customers. The analysis is based on the total bill, including a monthly service charge. The average residential seasonal monthly usage in 2007 was 142 kWh per month. An average customer would pay $40.52 per month at proposed rates, compared to $38.82 at current rates, or an increase of 4.4%.

Table 2

Bill Impacts for Residential Seasonal (R4) Customers

RESIDENTIAL SEASONAL (R4)			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
100	$35.55	$37.11	4.4%
250	$47.18	$49.25	4.4%
500	$66.55	$69.47	4.4%
750	$85.93	$89.70	4.4%
1000	$105.30	$109.92	4.4%
1500	$156.95	$163.82	4.4%
2000	$208.60	$217.72	4.4%
2500	$260.25	$271.62	4.4%
3000	$325.25	$352.87	8.5%

4.0 GENERAL SERVICE SINGLE PHASE

This classification applies to any non-Standard A service that does not fit the description of the residential class. Generally, it is comprised of commercial, administrative and auxiliary services. It also includes combination services where one property has a variety of uses and for all multiple services except residential. Single Phase service uses single phase power.

The bill analysis is based on the total bill, including a service charge. The average usage for General Service Single Phase customers in 2007 was 1,608 kWh per month. The average G1 customer would pay a monthly bill of $174.88 at proposed rates, compared to $167.53 at existing rates, or an increase of 4.4%.

Table 3

Bill Impacts for General Service Single Phase (G1)

GENERAL SERVICE SINGLE PHASE (G1)			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
1000	$114.75	$119.78	4.4%
2000	$201.55	$210.38	4.4%
5000	$461.95	$482.18	4.4%
10,000	$1,008.75	$1,053.18	4.4%
13,000	$1,353.75	$1,413.48	4.4%
16,500	$1,808.75	$1,982.23	9.6%
20,000	$2,263.75	$2,550.98	12.7%

5.0 GENERAL SERVICE THREE PHASE

This classification applies to non-residential customers who use three phase power.

The bill analysis is based on the total bill, including a service charge. The average usage for General Service Three Phase customers in 2007 was 11,624 kWhs per month. An average G3 customer would pay $1,089.68 at current rates, compared to $1,043.97 at existing rates, or an increase of 4.4%.

Table 4

Bill Impacts for General Service (G3)

GENERAL SERVICE THREE PHASE (G1)			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
5000	$504.00	$526.18	4.4%
10000	$903.00	$942.54	4.4%
25,000	$2,205.00	$2,301.54	4.4%
32,500	$3,067.50	$3,201.00	4.4%
40,000	$3,787.00	$3,953.63	4.4%
50,000	$5,230.00	$5,728.04	9.5%
60,000	$6,530.00	$7,351.54	12.6%

6.0 STANDARD A RESIDENTIAL ROAD/RAIL

This classification applies to residential customers who occupy premises funded in whole or in part by government, and who live in communities accessible by all season roads and by rail.

The bill analysis is based on the total bill, including a service charge. The average usage for Residential Road/Rail customers in 2007 was 319 kWhs per month. An average Standard A Residential Road Rail customer would pay $167.78 at current rates, compared to $175.16 at proposed rates, or an increase of 4.4%.

Table 5

Bill Impacts for Standard A Residential Road/Rail

STANDARD A RESIDENTIAL ROAD/RAIL			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
100	$50.96	$53.20	4.4%
250	$127.40	$133.00	4.4%
500	$272.95	$284.95	4.4%
750	$418.50	$436.90	4.4%
1000	$564.05	$588.85	4.4%
1500	$855.15	$892.75	4.4%
2000	$1,146.25	$1,196.65	4.4%

7.0 STANDARD A RESIDENTIAL AIR ACCESS

This classification applies to residential customers who occupy premises funded in whole or in part by government, and who live in communities that are not accessible by year-round roads.

The bill analysis is based on the total bill, including a service charge. The average usage for Standard A Residential Air Access customers in 2007 was 1,120 kWhs per month. An average Standard A Residential Air Access customer would pay $924.45 at current rates, compared to $965.08 at proposed rates, or an increase of 4.4%.

Table 6

Bill Impacts for Standard A Residential Air Access

STANDARD A RESIDENTIAL AIR ACCESS			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
100	$76.91	$80.29	4.4%
250	$192.28	$200.73	4.4%
500	$402.73	$420.73	4.4%
750	$613.18	$640.13	4.4%
1000	$823.63	$859.83	4.4%
1500	$1,244.53	$1,299.23	4.4%
2000	$1,665.43	$1,738.63	4.4%

8.0 STANDARD A GENERAL SERVICE ROAD/RAIL

This classification applies to general service customers who occupy premises funded in whole or in part by government, in communities that are accessible by year-round roads.

The bill analysis is based on the total bill, including a service charge. The average usage for Standard A General Service Road/Rail customers in 2007 was 1,934 kWhs per month. An average Standard A General Service Road/Rail customer would pay $1,125.77 at current rates, compared to $1,175.27 at proposed rates, or an increase of 4.4%.

Table 7

Rate Impacts for Standard A General Service Road/Rail

STANDARD A GENERAL SERVICE ROAD/RAIL			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
500	$291.10	$303.90	4.4%
1000	$582.20	$607.80	4.4%
1500	$873.30	$911.70	4.4%
2000	$1,164.40	$1,215.60	4.4%
2500	$1,455.50	$1,519.50	4.4%
3000	$1,746.60	$1,823.40	4.4%
4000	$2,328.80	$2,431.20	4.4%

9.0 STANDARD A GENERAL SERVICE AIR ACCESS

This classification applies to general service customers who occupy premises funded in whole or in part by government, in communities that are not accessible by year-round roads.

The bill analysis is based on the total bill, including a service charge. The average usage for Standard A General Service Air Access customers in 2007 was 3,083 kWhs per month. An average Standard A General Service Air Access customer would pay $2,595.55 at current rates, compared to $2,709.63 at proposed rates, or an increase of 4.4%.

Table 8

Rate Impacts for Standard A General Service Air Access

STANDARD A GENERAL SERVICE AIR ACCESS			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
500	$420.90	$439.40	4.4%
1000	$841.80	$878.80	4.4%
1500	$1,262.70	$1,318.20	4.4%
2000	$1,683.60	$1,757.60	4.4%
2500	$2,104.50	$2,197.00	4.4%
3000	$2,525.40	$2,636.40	4.4%
4000	$3,367.20	$3,515.20	4.4%

10.0 SREET LIGHTING

This classification applies to unmetered street lights. The energy consumption for streetlights is based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating.

The bill analysis is based on the total bill. The average usage for Standard A General Service Air Access customers in 2007 was 364 kWhs per month. An average Street Lighting customer would pay $32.69 at the proposed rates compared with $31.30 at current rates, an increase of 4.4%.

Table 9

Rate Impacts for Streetlights

STREET LIGHTING			
Scenario KWh	**Existing Bill**	**Proposed Bill**	**Percentage Change**
100	$8.60	$8.98	4.4%
200	$17.20	$17.96	4.4%
300	$25.80	$26.94	4.4%
400	$34.40	$35.92	4.4%
500	$43.00	$44.90	4.4%

TERMS AND CONDITIONS

1.0 INTRODUCTION

This exhibit provides evidence with respect to Remotes' terms and conditions of service for off-grid distribution customers. As required under Section 2.4 of the Distribution System Code ("Code"), Remotes has documented its Conditions of Service that describe its operating practices and connection policies. All of the components of the Conditions of Service as outlined in Section 2.4 are covered, as well as additional important information.

Our Conditions of Service is publicly available, and a summary of the terms is sent to all new customers at the time of connection and is included in a bill insert periodically.

Remotes updates its Conditions of Service when Codes change and for new industry initiatives that apply to its business.

Appendix A is the updated Conditions of Service for Remotes' Customers.

Hydro One Remote Communities
Conditions of Service

Table of Contents

1.0 INTRODUCTION

These Conditions of Service describe Hydro One Remote Communities Inc. (“Remotes") operating practices and connection policies and set out the terms and conditions upon which Remotes offers and the Customer accepts off-grid Distribution Services.

Terms contained in these Conditions of Service or in any contract for the supply of electricity by Remotes shall not prejudice or affect any rights, privileges, or powers vested in Remotes by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any Regulations thereunder.

The definition of terms used in these Conditions of Service appear in section 4.0. Capitalized expressions used in these Conditions of Service have the meaning ascribed in that section.

1.1 Identification of Distributor and Service Area

Remotes is an electricity distributor licenced by the Ontario Energy board (the “Board”) to Distribute electricity pursuant to Part V of the *Ontario Energy Board Act, 1998.* In accordance with its electricity Distribution Licence, Remotes owns and operates its off-grid Distribution System in the communities of

1. Armstrong.
2. Bearskin Lake.
3. Big Trout Lake.
4. Biscotasing.
5. Collins.
6. Deer Lake.
7. Fort Severn.
8. Gull Bay.
9. Hillsport.
10. Kasabonika Lake.
11. Kingfisher Lake.
12. Landsdowne House.
13. Oba.

14. Sachigo Lake.

15. Sandy Lake.

16. Sultan.

17. Wapakeka.

18. Weagamow.

19. Webequie.

20. Whitesand.

Remotes' service area may be changed from time to time with the approval of the Board.

1.2 Related Codes and Governing Laws

Remotes and the Customer shall comply with all Applicable Laws and with the Board's Codes, including the following in order of priority:

(a) The Affiliate Relationships Code
(b) The Distribution System Code

If there is a conflict between these Conditions of Service and any of the above, the documents listed above shall govern in order of priority. If there is a conflict between these Conditions of Service and a Connection Agreement executed by the Customer and Remotes, the Connection Agreement shall govern. The fact that a condition, right, obligation, or other term appears in these Conditions of Service but not in any of the documents listed above or in a Connection Agreement shall not be interpreted as, or be deemed grounds for finding of, a conflict.

1.3 Interpretations

In these Conditions of Service

(a) the singular includes the plural and vice versa;

(b) the use of one gender includes the other;

(c) the word person includes a firm, a body corporate, an unincorporated association or an authority;

(d) a reference to a person includes a reference to the person's executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation) and assigns;

(e) an agreement, representation or warranty on the part of or in favour of two or more persons binds or is for the benefit of them jointly and severally;

(f) specified periods of time refer to business days, and dates from a given day or the day of an act or event is to be calculated exclusive of that day;

(g) a reference to a day is to be interpreted as the period of time commencing at midnight and ending 24 hours later and does not include weekends and public holidays in the Province of Ontario. Public Holidays means the days designated by Remotes from time to time. Until otherwise designated, the public holidays are:

New Year's Day	Labour Day
Good Friday	Thanksgiving Day
Easter Monday	Christmas Day
Victoria Day	Boxing Day
Canada (Dominion) Day	
Civic Holiday (as celebrated in Metropolitan Toronto)	

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any contract between Remotes and any connected Customer or Generator, and these Conditions of Service supersede all previous Conditions of Service, oral or written, of Remotes as of the effective date of these conditions of service.

In the event of changes to these Conditions of Service, Remotes will issue a notice with the Customer's bill or issue a public notice in a local newspaper.

The Customer is responsible for contacting Remotes to obtain the current version of these Conditions of Service. Remotes may charge a reasonable fee for providing the Customer with a copy of these Conditions of Service.

1.5 Contact Information

For general inquiries, Remotes can be reached during normal business hours: Monday to Friday between 8:00-4:30 Eastern Standard Time.

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, Ontario

P7E 6G9

For Emergency purposes, Customers can call Remotes at:

1-888-825-8707 (24/7) or the number shown on the Customer’s bill.

1.6 Customer Rights

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

(a) of Remotes in providing Distribution and electrical supply Services to the Customer;
(b) of the Customer in being connected to its Distribution System; or
(c) of Remotes or the Customer in meeting their respective obligations or exercising their respective rights under these Conditions of Service, their Licenses and any other Applicable Laws.

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

1.7 Remotes’ Distributor Rights

1.7.1 Space and Access

The Customer shall provide Remotes, free of charge or rent, with a convenient and safe place for Remotes’ Facilities and Equipment on the Customer’s premises or approaches thereto. Remotes assumes no risk, and under no circumstances will Remotes be liable for any damages resulting from, arising out of or related to the presence of the Remotes Facilities and Equipment.

The Customer shall not allow any one other than an employee, or agent of Remotes, or a person lawfully entitled to do so, to repair, remove, replace, alter, inspect or tamper with the Remotes Facilities and Equipment on the Customer’s premises.

1.7.2 Powers of Entry

In addition to Remotes' rights under Section 40 of the Electricity Act, Remotes or its agents may enter the Customer's property at any time for any of the following purposes:

(a) to install, inspect, read, calibrate, maintain, repair, alter, remove, or replace a meter;
(b) to inspect, maintain, repair, alter, remove, replace, or disconnect wires or other facilities used to transmit or Distribute electricity;
(c) to inspect, maintain, repair, alter, remove, and replace Remotes Facilities and Equipment such as sentinel lights and streetlights.

Remotes will use commercially reasonable efforts to exercise this power of entry during normal business hours. The Remotes employee or agent exercising this power of entry will identify themselves with proper identification upon request.

1.7.3 Liability for Damage to Remotes Equipment

Remotes Facilities and Equipment located on the Customer's premises are in the care of and at the risk of the Customer. If any of Remotes' Facilities Equipment is damaged or destroyed by fire or any other cause other than ordinary wear and tear, the Customer shall pay Remotes the value of Remotes Facilities and Equipment or the cost of repairing or replacing same.

The Customer shall not build, or cause to build, plant or maintain any structure, tree, shrub or landscaping that would or could obstruct or endanger any Remotes Facilities and Equipment, interfere with the proper and safe operation of the Distribution System or any part thereof or affect Remotes' compliance with any Applicable Laws.

1.7.4 Customer's Equipment

Where applicable, Customer Equipment shall be subject to the reasonable acceptance of Remotes and the approval of the Electrical Safety Authority. Remotes' approval of any Customer Equipment is solely for the purposes of Remotes protecting its Distribution System and the Customer is solely responsible for protecting its own property.

1.7.5 Testing Customer's Load

The Customer shall allow Remotes to install and use meters and other equipment to conduct tests to determine the electrical characteristics of the Customer's load.

1.7.6 Automatic Reclosing Facilities

In order to safeguard and protect the Distribution System, Remotes installs facilities for automatic reclosing of circuit breakers (“Reclosing Facilities”), and from time to time may change the reclosing time of any such Reclosing Facilities.

The Customer shall be responsible for providing at his own expense:

(a) adequate protective equipment for any electrical apparatus which might be adversely affected by Reclosing Facilities; and
(b) such equipment as may be required for the proper reconnection of any apparatus or equipment of the Customer, without adversely affecting the proper functioning of the Reclosing Facilities.

1.7.7 Coming Into Force

These Conditions of Service shall be effective as of May 1, 2003, unless noted otherwise. Sections 2.1 of these Conditions of Service are effective as of November 1, 2000.

1.7.8 Force Majeure

Other than for any amounts due and payable by the Customer to Remotes, neither Remotes nor the Customer shall be held to have committed an event of default in respect of any obligation under these Conditions of Service if prevented from performing that obligation, in whole or in part, because of a Force Majeure Event.

If a Force Majeure Event prevents either party from performing any of its obligations under these Conditions of Service, that party shall:

(a) other than for Force Majeure Events related to acts of God, promptly notify the other party of the Force Majeure Event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practical;
(b) not be entitled to suspend performance of any of its obligations under these Conditions of Service to any greater extent or for any longer time than the Force Majeure Event requires it to do;
(c) use its best efforts to mitigate the effects of the Force Majeure Event, remedy its inability to perform, and resume full performance of its obligations;
(d) keep the other party continually informed of its efforts;
(e) other than for Force Majeure Events related to acts of God, provide written notice to the other party when it resumes performance of any obligations affected by the Force Majeure Event; and

(f) if the Force Majeure Event is a strike or a lock out of Remotes' employees, Remotes shall be entitled to discharge its obligations to notify its Customers in writing by means of placing an ad in the local newspaper.

1.8 Disputes

Customer complaints that cannot be resolved by calling Remotes at 1-888-825-8707 will be escalated to the appropriate supervisor who will serve as the primary point of contact. A customer service representative will make contact with the Customer, coordinate internal complaint activities, research, investigate, and follow up (when necessary) on the complaint to ensure resolution and closure.

In the event that issues cannot be resolved between Remotes and the Customer, complaints can be escalated to a third party complaints resolution agency which has been approved by the Board. Until such time as the Board approves an independent third party dispute resolution agency, the Board will assume this role.

2.0 DISTRIBUTION ACTIVITIES - GENERAL

2.0.1 Customer Supply

Remotes provides 24 hour power restoration response service free of charge to all classes of customers.

Customers are allowed one full disconnection/reconnection per year for maintenance purposes only. Disconnection and reconnection must be arranged several weeks in advance and will occur when crews are in the area on planned travel days.

2.0.2 Cable Locates

Upon request, Remotes will locate, if able, all secondary and primary underground cables without charge if no special trip is required. If Remotes is unable to locate an underground cable, Remotes will provide a service disconnection and reconnection without charge if no special trip is required.

In the event that a fault and/or damage is caused by the Customer or third party, the costs of repair will be charged to the party responsible, unless the fault and/or damage resulted from an incorrect cable locate performed by Remotes. In the event that structures, pavement, or landscaping make the cable inaccessible for repair, the Customer shall provide all civil work, supports, vegetation and landscaping associated with any repair/replacement of the cable that has failed.

In the event that a fault is detected on customer owned secondary underground service cable, that equipment will be disconnected by Remotes until repairs are made by the customer and reconnection is approved by the ESA. All costs associated with the disconnection and reconnection shall be the responsibility of the customer.

2.1 Connections

2.1.1 Building that Lies Along

Remotes charges new or existing Customers the Actual Cost of the connection. These costs may include, but are not limited to, the following:

(a) supply and installation of standard overhead transformation which includes secondary buss extensions or installations complete with conductor, and, anchoring;
(b) supply and installation of standard metering;
(c) an estimate and layout for the new service;
(d) connection of the Secondary or Primary Service at described Demarcation Points;
(e) primary and secondary wire.

Where applicable, Customers will also be responsible for:

(a) the supply of tree and vegetation management on a Customer's property;
(b) the easements or property agreements as required by Remotes; and
(c) a service upgrade charge, if a system expansion is triggered by a new connection
(d) the cost of any changes to the distribution system triggered by the connection, including staking and design.

2.1.1.1 Common Service Taps

A Customer shall provide, at its own expense, a secondary or primary pole or an underground primary voltage line ("Customer Supplied Facilities"), where required for compliance with the Electrical Safety Code. Remotes will not supply two neighbouring Customers from the same Customer Supplied Facilities unless all of the following conditions are met:

(a) the Customers and Remotes agree on the location of the portion of the Customer's built line to be owned by Remotes ("Common Line");
(b) the Common Line is located on property owned by one or both of the neighbouring Customers;
(e) the Common Line will be built by the Customers which will be owned by Remotes, and will be built to Remotes' Distribution Standards; and
(f) the Common Line is transferred with easements and tree clearing rights to Remotes for a nominal fee.

If all the above conditions cannot be met, and then each Customer will be required to supply, install, and own a separate line on their respective properties.

2.1.1.2 Service and Supply Locations

Remotes reserves the right to determine the service supply and connection locations. The Customer shall obtain Remotes' approval prior to the construction of electrical facilities.

2.1.1.3 Number of Service Entrances

Normally Remotes only permits one service entrance per property. Where it is not technically or financially feasible to have one service entrance, Remotes will connect additional service entrances on the same property.

Remotes will provide Customers with the option of having a Central Metered Service or a Primary Metered Service to combine the multiple service entrances.

2.1.1.4 Service Demarcation Points

Connections to the Distribution System are either Secondary Service connections or Primary Service connections.

2.1.1.5 Secondary Service

Secondary Service can be supplied when the Customers can be served directly from the Distribution System via a connection to the low-voltage side of the Distribution transformation.

For Secondary Service owned and maintained by Remotes, the Demarcation Point is:

(a) the top of the Customer's service entrance stack for overhead connections;

(b) the secondary transformer lugs or the buss connectors for underground connections; and

(c) the metering point for a central-metered service.

Maintenance of the portion of the Secondary Service owned by Remotes includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Remotes.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer lugs or the service bus connectors.

2.1.1.6 Customer Supplied Secondary Wire

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) service is underground;
(b) service size is greater than 400 amp.

2.1.1.7 Primary Service

The Demarcation Point is the primary live line clamp or line switch installed at Remotes's Distribution line or pole near the Customer's property line.

2.1.1.8 Service Size

Restrictions on the size of Secondary Service are as follows:

(a) Remotes shall review all Single Phase connections greater than 200 amps;
(b) Remotes shall review all Three Phase service connections of 400 amps or greater for system reliability and power quality impacts;
(c) to ensure system reliability it may be necessary to restrict service size below these levels.

2.1.1.9 Transformation

The maximum overhead transformer sizes for standard secondary voltages are:

(a) for a Single Phase overhead Standard Customer connection: 75 kVA
(b) for a Three Phase Standard Customer connection: 3 x 100 kVa

Customers requiring non-standard secondary voltages will be responsible for installing, owning, maintaining and operating their own transformer.

2.1.1.10 Tree and Vegetation Management

Customers are responsible for all initial and continuing tree trimming, tree and brush removal for all Secondary Services and Primary Services on a Customer's property. Clearances will conform to the Electrical Safety Code.

For Distribution lines built by the Customer, and where ownership is to be transferred to Remotes upon connection, the clearances will conform to distribution standards.

2.1.2 Offer to Connect

(a) Remotes will respond to requests for connection within the following timeframes:

i. by no later than 5 calendar days from receipt of the request. The response will specify any necessary information to be provided in order for Remotes to process the request.

ii. An offer to connect will be made by no later than 30 calendar days following receipt of all necessary information, if all obligations have been met.

(b) At a minimum, the Offer to Connect will contain:

i. a description of material and labour required to build the Expansion to connect the Customer;
ii. an estimated cost of Connection that would be revised based upon the actual costs incurred. The estimate will delineate costs attributed to engineering design, materials, labour, equipment, capacity charges (if applicable), administrative activities, and any outstanding energy and non-energy arrears;
iii. an estimated cost of Expansion if applicable that would be revised based upon the actual costs incurred. The estimate will delineate costs attributed to engineering design, materials, labour, equipment, capacity charges (if applicable), administrative activities, and any outstanding energy and non-energy arrears;
iv. identification of work for which the Customer may seek alternative bids;
v. terms and conditions for payments and deposits required;
vi. identification and payment of outstanding energy and non-energy arrears if applicable;
vii. Electrical Safety Authority authorization requirements;
viii. Capacity or system restrictions if applicable; and
ix. any additional information pertinent to the offer may be included.

(c) Payment for connections

The customer is responsible for all connection costs.

2.1.2.1 Alternative Bids

Customers may seek alternative bids for connection and Expansion facilities from qualified contractors if the construction work will not involve work on existing circuits.

The Customer shall be responsible for:

(a) selecting, hiring, and paying the selected contractor costs for the work eligible for the alternative bid and assuming full responsibility for the construction of that aspect of the Expansion project;
(b) administering the contract or paying Remotes to perform this service. Administering the contract includes acquisition of all required permissions, permits, and property rights as required;
(c) constructing to meet Remotes' design requirements;
(d) paying an inspection/commissioning fee for Remotes to inspect and commission the construction;
(e) paying the cost of easements or property agreements as required by Remotes;
(f) transferring ownership of the facilities built on public property or reserve land or servicing more than one Customer to Remotes for a nominal fee prior to connection; and
(g) paying costs for any additional design, engineering, and inspection/commissioning trips.

Remotes shall:

(a) provide the design specifications for the construction; and
(b) inspect and authorize the line for connection.

2.1.2.2 Private Ownership of Alternate Bid Construction

Normally, as a condition of connection, a line is transferred to Remotes' ownership. However, the Customer may own the Expansion if all of the following conditions are met:

(a) the portion of line to be constructed is for the sole benefit of one Customer; and
(b) the line to be constructed is located on Private Property or unorganized land.

2.1.3 Connection Denial

Remotes may deny connection to any Connection Applicant for any of the following reasons:

(a) refusal by the Connection Applicant to sign any agreements required to be executed by the Customer under these Conditions of Service;
(b) the connection will represent a contravention of the laws of Canada or the Province of Ontario;
(c) the connection will cause Remotes to be in violation of the conditions in Remotes' Distribution or Generation Licence;
(d) the connection will have an adverse effect on the reliability or the safety of the Generation/Distribution System;
(f) The connection will cause a material decrease in the efficiency of the Generation/Distribution System;
(g) the connection will have a material adverse effect on the quality of the Generation/Distribution service received by an existing Customer. Such affect on quality could be among other things, voltage flicker, harmonics or power outages
(h) the Connection Applicant is currently in arrears for Distribution Services, electricity supplied, or other services provided by Remotes;
(i) the connection is not in compliance with these Conditions of Service;
(j) the connection does not meet Remotes' design requirements;
(k) the connection will impose an unsafe situation to workers or the public beyond the normal risks inherent in the operation of the Distribution System;
(l) the connection will result in the inability of Remotes to perform planned inspections or maintenance;
(m) by order of the Electrical Safety Authority;
(n) the premises being connected are the subject of a stop work order under the Building Code Act ("Ontario");
(o) the connection will increase load beyond the capacity of the generation in service.

Remotes shall notify the Connection Applicant of the connection denial with reasons in writing. Remedies will be suggested to the Connection Applicant where Remotes is able. If it is not possible for Remotes to resolve the issue, it is the responsibility of the Connection Applicant to do so before a connection will be made.

2.1.4 Inspections before Connections

Remotes will not connect a Customer until the Customer has obtained the approval of the Electrical Safety Authority for all Customer owned electrical facilities.

2.1.5 Relocation of Plant

In the absence of existing agreements or legislation, Remotes is not obligated to relocate plant. Remotes may charge any person requesting a plant relocation all costs incurred by Remotes in relocating such plant, unless there is applicable legislation setting the costs, or the cost of any plant relocation are addressed in any agreements made by Ontario Hydro prior to April 1, 1999.

If the relocation is from public to Private Property, Remotes shall acquire easement rights at the expense of the requestor. This would include the actual cost to carry out the work, as well as any costs resulting from having to obtain the new easement or authorization equivalent.

2.1.6 Easements

2.1.6.1 Unregistered Rights

The Electricity Act provides that all property that is subject to unregistered rights prior to April 1, 1999 will continue to be subject to the right until the right expires or until it is released by the holder of the right.

2.1.6.2 Permits, Registered Easements and Owner Agreements

The majority of Remotes' land tenure rights are on provincial crown lands and federally-regulated First Nation Reserves.

Remotes requires provincial crown leases, land use permits or registered easements for facilities situated on provincial lands.

For facilities situated on federally-Regulated Reserve lands, Remotes requires permits under Section 28(2). These permits are normally issued by Indian and Northern Affairs Canada, following a negotiated agreement between the First Nation and Remotes.

For new or modified connections on provincial crown lands, Remotes may require a Customer to provide Remotes with a registered easement or land use permit with respect to Remotes Facilities and Equipment located on the property of the Customer or the property of a third party.

For new or modified connections on private lands, Remotes may require a Customer to provide Remotes with a registered easement with respect to Remotes Facilities and Equipment located on the property of the Customer or the property of a third party.

Permits or registered easements are required for facilities meeting any of the following conditions:

(a) any single or multi-phase line, underground or submarine cables, poles, anchors, or aerial occupation where the line crosses Private Property, including any common service taps;

(b) anchors on Private Property supporting Three Phase feeders, and any (single or multi-phase) structures supporting reclosers or voltage regulators where the poles are located on road allowance;

(c) any new plant being added to Remotes Facilities and Equipment which are the subject of an existing unregistered easement but does not include replacement/maintenance of the existing Remotes Facilities and Equipment.

2.1.7 Contracts

2.1.7.1 Implied Contracts

In all cases, notwithstanding the absence of a written contract, Remotes has an implied contract with any Customer that is connected to Remotes' Distribution System and receives Distribution Services from Remotes. The terms of the implied contract are embedded in these Conditions of Service, the Rate Handbook, Remotes' Rate schedules, Remotes' Distribution Licence and the Distribution System Code, as amended from time to time.

Any person or persons who take or use electricity delivered and/or supplied by Remotes shall be liable for payment for such electricity. Any implied contract for the supply of electricity by Remotes shall be binding upon the heirs, administrators, executors, successors or assigns of the Person or Persons who took and/or used electricity supplied by Remotes.

2.1.7.2 Service Agreements for New Connections (Agreement for Service)

Where Remotes is entitled under these Conditions of Service to recover the costs of a connection or Expansion, Remotes requires that the Customer execute an Agreement for Electrical Services (Agreement for Service) prior to Remotes commencing any construction activities in respect of the connection and/or Expansion. The Agreement for Service will describe the work to be performed by Remotes in respect of the connection or Expansion and any other conditions set forth in Remotes' offer to connect together with the applicable payment terms.

2.1.7.3 Cancellation

The Agreement for Service may be terminated by either party upon reasonable notice.

2.1.7.4 Special Contracts

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

(a) construction sites
(b) mobile facilities
(c) non-permanent structures
(d) special occasions, etc.
(e) generation and
(f) house move

2.2 Disconnection

Remotes reserves the right to disconnect the supply of electricity to or limit the amount that a Customer can consume for any of the following reasons:

(a) failure to pay Remotes any amounts due and payable for the Distribution of electricity or for supply of electricity under Section 29 of the Electricity Act;
(b) failure to pay any connection costs due and payable;
(c) non-payment of account security identified as a condition of service;
(d) contravention of the laws of Canada or the Province of Ontario.
(e) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the Distribution System.
(f) adverse effect on the reliability and safety of the Distribution System.
(g) a material decrease in the efficiency of the Distribution System.
(h) a material adverse effect on the quality of Distribution Services received by an existing connection;
(i) inability of Remotes to perform meter reading, planned inspections or maintenance;
(j) failure of the Customer to comply with a directive of Remotes that Remotes makes for the purposes of meeting its Licence obligations;
(k) failure of the Customer to comply with any requirements in these Conditions of Service or a term of any agreement made between the Customer and Remotes including but not limited to an Agreement for Services. Connection Agreement or a Capital Cost Recovery Agreement;
(l) failure of the Customer to enter into an Agreement for Services required by these Conditions of Service; or
(m) by order of the Electrical Safety Authority.

Remotes will provide the Customer with at least 7 days prior written notice before disconnecting or limiting the Distribution of electricity to a Customer. Disconnection does not relieve the Customer from having to pay Remotes any amounts payable by the Customer including electricity arrears. The Customer will be responsible for minimum bills until such time as Remotes removes the Remotes Facilities and Equipment associated with the Distribution of electricity to the Customer. Remotes may disconnect the supply of electricity to a Customer without notice in accordance with a court order, or for Emergency, safety or system reliability reasons. Under no circumstances will Remotes be liable for any damage resulting from, associated with or related to the Disconnection or the limitation of Distribution of electricity.

2.2.1 Community Disconnection Trips

Due to the size of Remotes' service territory, Remotes organizes its disconnection activities by community. If Remotes determines that disconnection is warranted, every attempt will be made to establish personal contact with the customer prior to disconnection.

Personal contact is defined as one of the following:

i. Telephone conversation with the customer prior to service disconnection
ii. Face to face discussion with the customer
iii. A letter sent to the customer prior to a collection trip.

2.2.3 Reconnection

Where the reason for the Disconnection of the Distribution of electricity has been remedied to Remotes' satisfaction, Remotes shall reconnect a Customer.

If disconnected customers are able to make payment/payment arrangements during a community collection trip, Remotes will reconnect these customers prior to leaving the community.

Under any of the following circumstances, Remotes requires that the Customer obtain the approval of the Electrical Safety Authority prior to Remotes reconnecting the service:

(a) where Remotes has reason to believe that the wiring may have been damaged or altered ;
(b) service has been disconnected for modification of Customer wiring;
(c) service has been disconnected for a period of six months or longer; or
(d) where the service was disconnected as a result of an adverse affect on the reliability and safety of the Distribution System.

2.2.4 Disconnection and Reconnection Related Charges

A collection charge shall apply in cases where it is necessary for Remotes to make a trip to the Customer's premises to collect payment for an overdue account, disconnect service, install a load limiter, or reconnect service.

If Reconnection takes place during a community collection trip or regularly scheduled trip, a reconnection charge will be applied.

If a special trip to reconnect a customer is required, the customer shall pay the actual costs for the special trip.

2.2.5 Unauthorized Energy Use

Remotes reserves the right to disconnect the Distribution of electricity to a Customer for causes not limited to energy diversion, fraud or abuse on the part of the Customer. Such service may not be reconnected until the Customer rectifies the condition and provides full payment to Remotes of all costs incurred by Remotes arising from Unauthorized Energy Use, including inspections and repair costs, and the cost of disconnection and reconnection.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guarantee of Supply

Remotes will endeavour to use reasonable diligence in providing a regular and uninterrupted supply of electricity, but does not guarantee a constant supply or the maintenance of unvaried voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities. Customers may require special protective equipment, which is subject to the approval of Remotes, at their premises to minimize the effect of momentary power interruptions.

2.3.2 Power Quality

Remotes shall follow Good Utility Practices in terms of its guidelines and standards where applicable but will not guarantee an unvaried voltage or frequency.

2.3.2.1 Power Quality Inquiries

Remotes maintains a 24 hour call answer service for the purpose of receiving inquiries from Customers regarding power interruptions, power quality incidents, and incidents related to the integrity or safety of its Distribution System.

For Customer power quality inquiries other than interruptions, including substandard voltage conditions, or other power disturbances, the initial response time will vary depending on the nature of the complaint.

If after an initial investigation, the power quality issue remains unresolved, and it is determined that further detailed engineering study is required, Remotes shall advise the Customer of an intended course of action. If through an initial assessment, or subsequent detailed investigation, it is determined that the source of a power quality complaint is being caused by the Customer’s own equipment, then Remotes may charge the Customer all or a portion of the costs of carrying out the investigation.

2.3.2.1 Interruption of Supply

Remotes reserves the right to interrupt the supply of electricity in response to a shortage of supply or in order to inspect, maintain, repair, alter, remove, replace or disconnect wires or other facilities used to Distribute electricity. Remotes may, but is not obligated to, notify affected Customers in advance of planned power interruptions and has the right to interrupt without notice.

2.3.3 Electrical Disturbances

2.3.3.1 Customer Responsibilities

In general, Customers are expected to operate their electrical equipment in such a manner as to not cause any unacceptable voltage fluctuations, voltage unbalance, harmonics, or other disturbances that could negatively impact other Customers connected to the Distribution System, or Remotes Facilities and Equipment.

If it is determined that unacceptable conditions are being caused by any Customer-owned equipment, then the owner of such equipment will be expected to take appropriate remedial action to correct the condition. Depending on the severity of the supply condition, Remotes may require that such equipment be disconnected from the Distribution System until corrective measures can be taken.

Remotes' standards and guidelines for various electrical disturbances are as described below:

2.3.3.2 Voltage and Current Harmonics

Remotes will follow Good Utility Practice for establishing limits on harmonic current emissions and voltage distortions. The Customer shall ensure that the equipment at their facility does not generate harmonic currents that exceed acceptable industry practices.

2.3.3.3 Voltage Fluctuations and Flicker

Voltage fluctuations will normally be within the limits of the Remotes voltage flicker curve, which is based on the GE Borderline of irritability for incandescent lighting.

2.3.3.4 Frequency Fluctuations

In general, the frequency of AC power on the Remotes Distribution System will be dictated by the supply frequency of the Distribution System. However because of the significantly larger ratio of large community loads to typical diesel generation capacity in remote communities some variations are to be expected. Remotes will follow good utility practice to minimize the magnitude and extent of frequency fluctuations by limiting the allowable size of a single load to connect to the system. All proposed connections of motors/inductive loads 400 amps and higher must be reviewed compared to generation station capacity since these motors must be less then 5% of the smallest diesel generator's capacity. Any motors that are larger then 5% will require some form of reduced voltage start to prevent any adverse effects on other customers. Engineered drawings are to be provided to Remotes of all major loads prior to connection approval.

2.3.3.5 Over-voltages

In general, Remotes will follow Good Utility Practice to minimize the magnitude and extent of such short-term over-voltages.

2.3.4 Standard Voltage Offerings

Remotes will supply standard voltages only. The Customer will supply transformation for all other voltages required.

Standard secondary voltages are:

(a) Single Phase – 120/240 volt 3 wire;
(b) Three Phase – 120/308 volt 4 wire or 347/600 volt 4 wire

2.3.4.1 Primary Voltages

Remotes shall provide or extend only one Primary Voltage to service a connection or development, unless additional Primary Voltage is already present or the development cannot be effectively fed from the existing supply. Customers requesting a Primary Service should contact Remotes to determine the voltage available at the particular location.

2.3.5 Voltage Guidelines

Standard operating conditions are:

Standard Voltages Table 1	
Nominal	Recommended Voltage Variation Limits for Circuits up to 1000 volts, at the Service Entrance.

System Voltages	Extreme Operating Conditions	Normal Operating Conditions		Extreme Operating Conditions
Single Phase 120/240 240	 108/216 212	 110/220 220	 125/250 250	 127/264 264
Three Phase 4 –Wire 120/208Y 346/600Y	 108/187 311/540	 112/194 318/550	 125/216 360/625	 132/229 381/660

These voltage guidelines relate to long term steady state levels and do not include short term or transient disturbances.

2.3.6 Back-up Generators

Customers with portable or permanently connected Emergency generation capability shall comply with all the applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that the Customer Emergency generation does not back feed on the Distribution System.

Customers with permanently connected Emergency generation equipment shall notify Remotes regarding the presence of such equipment.

2.3.7 Metering

For Retail settlement and billing purposes, Remotes shall provide, install, own and maintain a Meter Installation for all Customers.

The type of metering will be based on the Customer’s Rate class, energy consumption and peak load. The security and accuracy of metering will be maintained under Regulations and standards established by Measurement Canada and Remotes.

2.3.7.1 Single Phase – Secondary Metered

For new Secondary Metered connections, metering shall be based on estimated load. Customers who are estimated to have an average monthly peak load under 50 kW shall be metered on kilowatt-hours (“kWh”) only. Customers estimated to have an average monthly peak load over 50 kW shall be metered on monthly kW as well as kWh.

For existing Customers, metering shall be based on the actual average monthly peak load for the previous year. Customers with an average monthly peak load, in the previous year, under 50kW shall be based on kWh. Customers that had an average monthly peak load, in the previous year, over 50 kW shall be metered and billed on monthly kW demand as well as kWh.

2.3.7.2 Three Phase – Secondary Metered

All Three Phase Customers will be metered for energy usage in kWh and for peak monthly kW demand and/or monthly peak kVA depending on the peak load and power factor.

2.3.7.3 Central Metered Services

Remotes, in its discretion, may supply a Single-Phase Customer with a central metering service to two or more buildings. If Remotes chooses to do so, the Customer shall:

(a) pay the cost of the central metering;
(b) comply strictly with the Electrical Safety Code and Remotes Remote Communities' Distribution Standards;
(c) have an appropriately sized main disconnect and equipment for each service connected to the central metering service; and
(d) supply and install, at its own expense, all conductors, poles, and underground conductors, as required.

The maximum number of services to be connected at the central metering point is four. Additional services must be connected downstream of the central metering point.

2.3.7.4 Primary Metered Services

When a Customer requests a primary metered service (connected at the primary voltage level), the Customer shall install, own, and maintain, at its own expense, the entire distribution system required downstream from the metering point which includes conductors, poles, and transformation.

When secondary metering is not practical to meter the Customer's load, Remotes will provide the primary metering at cost. If secondary metering is practical, the Customer will pay Remotes the cost of supplying and installing the primary metering and secondary metering. Secondary metering is considered practical when the Customer's entire load can be metered on the secondary side of the transformation.

2.3.7.5 Travel Trailer, Public and Private Camping Parks

The park authority/owner will provide, own, and maintain all Distribution facilities, including transformers and individual metering as desired, within the park boundary. Such facilities will be subject to the approval of the Electrical Safety Authority. All electricity supplied for park services will be combined and billed under one General Service account.

Remotes will determine the type of metering required. If secondary metering is not practical, a primary metering service will be required at or near the park property limit. When primary metering is required, the customer will install, own, and maintain the entire distribution system beyond the metering point, which will include poles, conductors, transformers and all other electrical equipment. A transformation allowance will be applied to the customer's energy bill.

2.3.7.6 Location of Metering

As determined by the layout, the Electrical Safety Code, the Ontario Building Code and Remotes, the meter(s) will be located on the exterior of the building:

(a) on the front side of the building facing the street or roadway;
(b) on the side of the building, not more than 3 metres from the front facing the street or roadway.

For metering installed on poles, the pole will be owned and installed by the Customer.

2.3.7.7 General

Remotes shall, at all reasonable hours, have the right to inspect, repair, replace and remove any part of the metering installation and have free access to the premises for that purpose.

2.3.7.8 Current Transformer Boxes

Customers are responsible for supplying, owning, and maintaining meter bases, except for Complex Metered Three Phase services where Remotes requires and supplies at no charge a "P" base enclosure. For services requiring additional metering such as instrument transformers, the Customer is required to supply and install the following, all of which has to be approved by the Electrical Safety Authority and Remotes:

(a) instrument transformer enclosures with a minimum dimension of 90cm x 90cm x 30cm;
(b) all required conduit as specified by Remotes; and
(c) where appropriate a self contained 400 amp meter base complete with a 400 amp current transformer. Remotes will provide the Customer with an allowance for the cost of the current transformer.

For Central Metering services, a current transformer enclosure is not required; however, Remotes can supply and install the conduit and meter base for the Customer for a charge.

2.3.7.9 Meter Reading

Remotes shall, at all reasonable hours, have the right to read, inspect, repair, replace and remove any part of the metering installation and have free access to the premises for that purpose.

If unable to access the premises, Remotes shall attempt to arrange access to the premises at a time convenient for both Remotes and the Customer. At its discretion, Remotes may elect to have the meter read by the Customer, and the results provided to Remotes

If the Customer does not accommodate Remotes' request for meter reading or access, the Customer shall be informed in writing of their obligation to contact Remotes and arrange appropriate access to the meters, or provide Remotes with the requested meter readings.

In order to ensure accurate billing and proper operation, Remotes needs to read and visually inspect the meter annually. In the event that Remotes cannot access the meter for this purpose after the Customer has been contacted several times, Remotes reserves the right to demand a relocation of the meter at the Customer's expense. If the situation is not rectified, Remotes may ultimately disconnect the Customer.

2.3.7.10 Final Meter Reading

When a final meter reading is required for billing purposes, the Customer shall provide Remotes with at least five business days notice of the date the billing is to be discontinued so that Remotes can obtain a final meter reading as close as possible to the required date. The Customer shall provide access to Remotes for this purpose. If access is not obtained, and a final meter reading is not possible, the Customer shall pay a sum based on estimated electricity used since the last meter reading.

2.3.7.11 Faulty Registration of Meters

The security and accuracy of metering is governed by the federal Electricity and Gas Inspection Act and associated Regulations, under the jurisdiction of Measurement Canada. Remotes' meters are required to comply with the accuracy specifications established by the Regulations made under that Act.

Remotes is responsible for advising the Customer of any meter error of which it becomes aware and its magnitude and of his or her rights and obligations under the *Electricity and Gas Inspection Act* (Canada). Remotes is also responsible for subsequently settling actual payment differences with the Customer.

In the event of incorrect electricity usage registration, Remotes will rectify billing errors on the following basis:

2.3.7.12 Overbilling

Where a billing error, from any cause, has resulted in a Customer being over billed, and where Measurement Canada has not become involved in the dispute, Remotes shall credit the Customer with the amount erroneously billed. The credit Remotes remits shall be the amount erroneously billed for up to a six-year period.

Where the billing error is not the result of Remotes' standard billing practices, i.e., estimated meter reads, Remotes shall pay interest on the amount credited to the relevant party equal to the prime rate charged by Remotes' bank.

2.3.7.13 Underbilling

Where a billing error, from any cause, has resulted in a Customer being under billed, and where Measurement Canada has not become involved in the dispute, Remotes shall charge the Customer with the amount not previously billed. In the case of a residential Customer who is not responsible for the error, the allowable period of time for which the Customer may be charged is two years. For non-residential Customers or for instances of willful damage, the relevant time period is the duration of the defect.

2.3.7.14 Meter Dispute Testing

Measurement Canada has jurisdiction, under the federal Electricity and Gas Inspection Act, in a dispute between Remotes and its Customer where the condition or registration of a meter or metering installation is in question. Remotes will inform Customers of the assistance provided by Measurement Canada in dispute investigations.

If the services of Measurement Canada are requested by the Customer to resolve the issue, Remotes will charge the Customer for the costs of processing the application to Measurement Canada and removing and transporting the meter to a testing location. If the dispute is substantiated by Measurement Canada and the resolution is in the favour of the Customer, the costs will not be recovered from the Customer.

2.4 Rates and Charges

The Ontario Energy Board approves the Rates Remotes charges for each Rate classification. The Ontario Energy Board also approves all the Miscellaneous Distribution Charges that Remotes levies.

The main Rate classifications are year-round residential, seasonal-residential, General Service, street lighting, Road Rail Residential, Air Access Residential, Road Rail General Service and Air Access General Service.

To assign a Customer to the appropriate Rate classification, Remotes considers the nature and use of the Customer’s electricity service.

The OEB approved Rates and charges are as set out in the Schedule of Rates available from Remotes upon request. Notice of Rate changes shall be mailed to all Customers with the first bills issued using the revised Rates.

2.4.1 Service Connection

Remote Communities charges customers the Actual Cost of the connection to connect to its distribution system.

2.4.2 Energy Supply

Remotes' rates combine the charges for all the electrical services (generation and distribution)

2.4.3 Deposits

Whenever required by Remotes, including but not limited to, as a condition of supplying or continuing to supply Distribution Services, the Customer shall provide and maintain security in an amount that Remotes deems necessary and reasonable.

Remotes will request account security deposits from all applicants for service who do not have a good payment history. For new customers, Remotes will request account security deposits unless a credit check shows that the applicant is an acceptable credit risk or the applicant can provide a reference letter from a prior utility attesting to a good payment history.

For residential customers, a good payment history is defined as:

1) The customer does not owe arrears at another Remotes' account and
2) The customer has been served by Remotes within the previous six months and has no more than 1 disconnection notice; no more than one NSF cheque and/or no collection/disconnection charges over the last twelve month period of service; or
3) During search of the consumer credit database (with customer's permission), the customer is matched with a file and is deemed an acceptable credit risk; or
4) The customer can provide a reference letter from a prior utility that attests to a good payment history.

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For General Service customers, a good payment history exists when

1) The applicant does not owe arrears at another Remotes account; and
2) The applicant has been served by Remotes within the previous six months and has no more than 1 disconnection notice, no more than one NSF cheque and/or no collection/disconnection charges over the last 5 year period of service; or
3) During a search of the consumer credit database (with the applicant's permission), the applicant is matched with a file and is deemed an acceptable credit risk; or
4) The applicant can provide a reference letter from a prior utility that shows a good payment history for a 5 year period.

Remotes will collect a security deposit from Customers who have been identified to have a poor credit history.

Account security deposits must be in the form of (I) cash or cheque; or (ii) an irrevocable letter of credit from a Chartered Canadian Bank or Credit Union. Remotes will not accept third party guarantees.

Account security deposit levels will be in an amount to cover Remotes' exposure and based on billing frequency and payment cycle/period.

Account security deposit levels for new Customers or Customers who have no payment history with Remotes shall be determined based on average electricity consumption for similar Customers.. Applicants may pay the security deposit in equal installments over 4 months or in a shorter time frame at the applicants' discretion.

Refund of account security on residential accounts occurs when a satisfactory payment record is demonstrated over 12 consecutive months. When the account is terminated, the security amount will be credited on the Customer's final bill and any surplus will be refunded by cheque. For all other accounts, the account security deposit will be held until a satisfactory payment record is demonstrated over 5 years.

Interest on cash security deposits will be calculated and credited on the Customer's bill on a quarterly basis. Quarterly interest Rates will be determined by Remotes quarterly and is the prime business rate, as indicated on the Bank of Canada website, less two percent. The interest will be paid out at least once every 12 months or on return of the deposit or on closure of the account, and may be credited to the account..

2.4.4. Billing

In this section 2.4.4, references to monthly, quarterly, and annually are notional and approximate time periods only. They are not to be construed as calendar-based time periods.

2.4.4.1 Billing Frequency

Depending on Rate classification, Customers are billed on a monthly or quarterly frequency.

2.4.4.2 Meter Read Frequency

Remotes reads meters on a monthly, quarterly, or annual frequency, depending on Rate classification. Where Remotes is unable to obtain a meter reading, for any reason, the customer may be requested to provide a meter reading.

2.4.4.3 Use of Estimates

In months where a bill is issued, but no reading is obtained, Remotes estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premises, or a pre-determined quantity if there is no historical usage information available.

2.4.4.4 Budget Billing Plan

A budget billing plan is available to all Customers except monthly read Customers. To help smooth electricity costs over the year, the plan bills an equal portion of the previous year's charges per bill period then reconciles the balance owing in the anniversary month. Adjustments may be made to the regular budget bill amount due to Rate or usage changes.

2.4.5 Payments and Overdue Account Interest Charges

2.4.5.1 Payment Options

Customers may pay their electricity bills using any of the following methods: cheque or money order mailed with the remittance stub portion of the bill to Remotes at the address on the stub; in person at most Canadian financial institutions; through automated banking machines, telebanking or Internet bill payment services as offered through their financial institution. All payments should be in Canadian dollars.

Remotes also offers Electronic Fund Transfers.

2.4.5.2 Late Payment Charges

Customers are allowed 21 days from the billing date on the statement to make payment. A late payment charge may be charged on overdue accounts whether the bill is based on a meter reading or by Remotes' estimate where meter reading has not occurred. The OEB approved late payment charge is set at 1.5 per cent compounded monthly (19.56 per cent per annum). Where a partial payment has been made on or before the due date, the late payment charge will apply only to the amount of the bill outstanding at the due date.

2.5 Customer Information

Remotes shall not disclose specific information about a Customer unless the release of information has been authorised by that particular Customer or unless necessary for compliance with any Board approved Code or standard.

Remotes shall not disclose Customer information to a third party without the consent of the Customer in writing, except where Customer information is required to be disclosed, as follows:

(a) for billing purposes;
(b) for law enforcement purposes;
(c) for the purpose of complying with a legal requirement; or,
(d) for the processing of past due accounts.

Customers have the obligation to provide Remotes with information that is true, complete, and correct. The information is used to provide Customer service, deliver and/or supply energy, manage Customer accounts and assess credit history regarding the need for account security. Remotes may verify the accuracy of all information provided and may obtain additional credit information from a credit-reporting agency as required.

2.5.1 Provision of Current Usage Data to Customers

Customers with cumulative volume and Demand Meters shall receive their current usage data on their electricity bill from Remotes.

3.0 CUSTOMER CLASS SPECIFIC

3.1 Non Standard A Residential

Under Section 79 of the *Ontario Energy Board Act, 1998* and associated Regulations, non-government customers within Remotes' service territory are eligible to receive Remote and Rural Rate Protection.

3.1.1 Year Round Residential R2

This Customer Rate classification refers to a residential service that is the principal residence of the Customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classified as year round residential, all of the following criteria must be met:

(a) occupants must state that this is their principle residence for purposes of the Income Tax Act;
(b) the occupant must live in this residence for at least 8 continuous months of the year;
(c) the address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc;
(d) occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential R4

This Rate classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps.

3.2 Non Standard A General Service

This Rate classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

3.2.1 General Service, Single Phase G1

This classification is applicable to General Service Single Phase Customers.

3.2.2 General Service, Three Phase G3

This classification is applicable to General Service Three Phase Customers.

3.3 General Service over 50 kW

Customers estimated to have an average monthly peak load over 50 kW shall be metered on monthly kW as well as kWh.

3.4 Unmetered Connections

There are instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Remotes reserves the right to review all cases and may request a meter be installed at its sole discretion.

All unmetered connections fall under the General Service or Lights Rate classifications.

Unmetered connections may include the following:

3.4 Street Lighting

The energy consumption for street lights is estimated based on Network's profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

(a) An energy charge based on installed load, at a Rate approved annually (Dollars per kWh x # of fixtures x billing);
(b) A pole rental charge approved annually, when the light is attached to a Remotes pole;

Remotes must approve the location of new lighting installations on its line poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the Distribution System.

3.5 Standard A Service

Standard 'A' rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue.

Exceptions to these are:

- Crown Corporations
- Community Centres/Halls
- Ice Rinks/Arenas
- Radio, Televisions and Cable
- Libraries

Any Standard 'A' account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard 'A' account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature.

An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source.

An example of direct funding is an MTO account paid directly by MTO.

An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada.

3.5.1 Standard A Residential Road/Rail

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

3.5.2 Standard A Residential Air Access

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

3.5.3 Standard A General Service Road Rail

This classification applies to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

3.5.4 Standard A General Service Air Access

This classification applies to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

4.0 GLOSSARY OF TERMS

"Act" means the Ontario Energy Board Act, 1988, S.O. 1998, C. 15, Schedule B;

"Actual Cost" means Remotes' charge for equipment, labour and materials at Remotes' standard rates plus Remotes' standard overheads and interest thereon;

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"Applicable Laws" means any and all Applicable Laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments, or decree or any requirements or decision or agreement with or by any governmental or governmental department, commission, board, court authority or agency;

"Board" means the Ontario Energy Board;

"Code" means the Distribution System Code;

"Complex Metering Installation" means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed;

"connection" means the process of installing and activating connection assets in order to Distribute electricity to a Customer;

"connection applicant" means the person or entity applying for a connection either on the person or entity's own behalf or on behalf of another person.

"Customer" means a person who is connected to the Distribution System. If an account is opened in more than one person's name, all such persons are Customers and are jointly and severally responsible for compliance with these Conditions of Service and to pay the Rates and charges in accordance with these Conditions of Service;

"Customer Equipment" means all electrical and mechanical equipment used by the Customer and does not include any Remotes Facilities and Equipment;

"Demand Billed Customer" means a demand metered customer with average monthly peak demand greater than 50 kWs over 12-months that is ready monthly and billed on kW demand as well as kWh-hour energy.

"Demand Meter" means a meter that measures a Customer's peak usage during a specified period of time;

"Demarcation Point" means the physical location at which Remotes responsibility for operational control and ownership of Distribution equipment including connection assets ends at the Customer;

"Disconnection" means a deactivation of connection assets that results in cessation of Distribution Services to a Customer;

"Distribute" or "Distribution" means with respect to electricity, means to convey electricity at voltages of 50 kV or less;

"Distribution Losses" means energy losses that result from the interaction of intrinsic characteristics of the Distribution network such as electrical resistance with network voltages and current flows;

"Distribution Loss Factor" means the factor(s) by which metered loads must be multiplied such that when summed it equals the total measured load at the supply point(s) to the Distribution System;

"Distribution Services" means services related to the Distribution of electricity and the services the Board has required distributors to carry out, for which a charge or Rate has been approved by the Board under Section 78 of the Act.

"Distribution System" means Remotes' system for distributing electricity, and includes any structures, equipment or other things used for that purpose. The Distribution System is comprised of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main Distribution Systems;

"Distribution System Code" means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to Customers and provides minimum technical operating standards of Distribution System;

"Electricity Act" means the Electricity Act, 1998, S.O. 1998, C.15, Schedule A;

"Electrical Safety Authority" or "ESA" means the person or body designated under the Electricity Act Regulations as the Electrical Safety Authority;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a Distribution System or supply of electricity that could adversely affect the reliability of the electricity system;

"Enhancement" means a modification to the existing Distribution System that is made for purposes of improving system operating characterizes such as reliability of power quality or for relieving system capacity constraints resulting, for example, from general load growth;

"Expansion" means an addition to the Distribution System in response to a request for additional Customer connections that otherwise could not be made

"Force Majeure Event" shall be deemed to be a cause reasonably beyond the control of the party whose inability as aforesaid is involved such as, but without limitation to, strike of that party's employees, damage or destruction by the elements, accident to the works of that party, fire explosion, war the Queen's enemies, legal act of the public authorities, insurrection, act of God or inability to obtain essential services or to transport materials, products or equipment because of the effect of similar causes on that party's suppliers or carriers.

"Non Standard A General Service" The rate classification applicable to any Non Standard A service that does not fit the description of the residential classes. Generally, it is comprised of commercial, administrative, auxiliary and recreational-type services. It includes combination-type services where the owner of one property makes a variety of uses of the service, and all multiple services, except residential.

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

"Remotes Facilities and Equipment" means Remotes's meters, wires, poles, cables, transformers, any other structures, equipment, all other appliances and equipment or other things used for Distributing electricity; generators etc?

"Lies Along" means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where Remotes has Remotes Facilities and Equipment of the appropriate voltage and capacity.

"Measurement Canada" means the Special Operating Agency established in August 1996 by the Electricity and Gas Inspection Act, 1980-81-82-83, C.87 and Electricity and Gas Inspection Regulations (SOR/86-131);

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

"Metering Services" means installation, testing, reading, and maintenance of meters;

"Monthly Billing" means a notional 30 day month for billing cycle, not a calendar month;

"Multiple Residential Properties" means a property, which provides separate living accommodation for two or more families. It does not include properties used for short-term occupancy such as hotels, motels, etc.;

"Ontario Energy Board Act" means the Ontario Energy Board Act, 1998, S.O. 1998, C.15, Schedule B;

"Primary Service" means a connection directly to Remotes's Primary Facilities. Customer owns all conductor, supports and civil works located on their property;

"Property" means any property owned or used by a Customer or a third party and does not include any public street or highway

"Rate" means any Rate, charge or other consideration, and includes a penalty for late payment;

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor Rates;

"Regulations" means the Regulations made under the Act or the Electricity Act;

"Secondary Service" means a connection to the low voltage side of Remotes's transformer located on the Distribution System. Remotes may own the conductor and the Customer always owns all supports and civil works on the Customer's property;

"Single Phase" means a system that supplies a single alternating current voltage supply.

"Three Phase" means a system having three distinct alternating current voltages 120 degrees between each voltage.

"Unaccounted for Energy" means all energy losses that cannot be attributed to Distribution losses. These include measurement error, errors in estimates of Distribution losses and Unmetered Loads, energy theft and non-attributable billing errors;

"Unmetered Loads" means electricity consumption that is not metered and is billed based on estimated usage.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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

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 generation, transmission and/or distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the generation, transmission and/or 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.

Effective Dates

RATES – May 1, 2009 for all consumption or deemed consumption service used on or after that date

MISCELLANEOUS CHARGES – May 1, 2009 for all charges billed to customers on or after that date

SERVICE CLASSIFICATIONS

Non Standard A Residential
Year-Round Residential - R2
This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential – R4
This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps.

Non Standard A General Service
This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

General Service Single Phase – G1
This classification is applicable to General Service Single Phase customers.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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General Service Three Phase – G3

This classification is applicable to General Service Three Phase customers.

General Service over 50 kW

Customers estimated to have an average monthly peak load over 50 kW shall be metered on monthly kW as well as kWh.

Unmetered Scattered Load

This classification applies where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Remotes reserves the right to review all cases and may request a meter be installed at its sole discretion. All unmetered connections fall under the General Service or Lights rate classifications.

Street Lighting

The energy consumption for street lights is estimated based on Remote's profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

- An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);

- A pole rental charge approved annually, when the light is attached to a Remotes pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system.

Standard A Service

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue.
Exceptions to these are:

- Crown Corporations

- Community Centres/Halls

- Ice Rinks/Arenas

- Radio, Televisions and Cable

- Libraries

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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Standard A Residential Road/Rail

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

Standard A Residential Air Access

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

Standard A General Service Road/Rail

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

Standard A General Service Air Access

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

MONTHLY RATES AND CHARGES

Year-Round Residential – R2

Service Charge	$	17.17
Energy Charge First 1,000 kWh	$/kWh	0.0809
Energy Charge Next 1,500 kWh	$/kWh	0.1078
Energy Charge All Additional kWh	$/kWh	0.1625

Seasonal Residential – R4

Service Charge	$	29.02
Energy Charge First 1,000 kWh	$/kWh	0.0809
Energy Charge Next 1,500 kWh	$/kWh	0.1078
Energy Charge All Additional kWh	$/kWh	0.1625

General Service Single Phase – G1

Service Charge	$	29.18
Energy Charge First 6,000 kWh	$/kWh	0.0906
Energy Charge Next 7,000 kWh	$/kWh	0.1201
Energy Charge All Additional kWh	$/kWh	0.1625

General Service Three Phase – G3

Service Charge	$	36.54
Energy Charge First 25,000 kWh	$/kWh	0.0906
Energy Charge Next 15,000 kWh	$/kWh	0.1201
Energy Charge All Additional kWh	$/kWh	0.1625

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

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Street Lighting

Energy Charge	$/kWh	0.0898

Standard A Residential Road/Rail

Energy Charge First 250 kWh	$/kWh	0.5320
Energy Charge All additional kWh	$/kWh	0.6078

Standard A Residential Air Access

Energy Charge First 250 kWh	$/kWh	0.8029
Energy Charge All additional kWh	$/kWh	0.8788

Standard A General Service Road/Rail

Energy Charge	$/kWh	0.6078

Standard A General Service Air Access

Energy Charge	$/kWh	0.8788

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection/Disconnection/Load Limiter/Reconnection – if in Community	$	65.00

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

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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.

SERVICE CLASSIFICATIONS

Non Standard A Residential
Year-Round Residential - R2
This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

• Occupants must state that this is their principal residence for purposes of the Income Tax Act;

• The occupant must live in this residence for at least 8 continuous months of the year;

• The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;

• Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential – R4
This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps.

Non Standard A General Service
This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

General Service Single Phase – G1
This classification is applicable to General Service Single Phase customers.

General Service Three Phase – G3
This classification is applicable to General Service Three Phase customers.

General Service over 50 kW
Customers estimated to have an average monthly peak load over 50 kW shall be metered on monthly kW as well as kWh.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

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

Unmetered Scattered Load

This classification applies where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Remotes reserves the right to review all cases and may request a meter be installed at its sole discretion. All unmetered connections fall under the General Service or Lights rate classifications.

Street Lighting

The energy consumption for street lights is estimated based on Remote's profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

- An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);
- A pole rental charge approved annually, when the light is attached to a Remotes pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system.

Standard A Service

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue.
Exceptions to these are:

- Crown Corporations
- Community Centres/Halls
- Ice Rinks/Arenas
- Radio, Televisions and Cable
- Libraries

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada.

Standard A Residential Road/Rail

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

Standard A Residential Air Access

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

Standard A General Service Road/Rail

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

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Standard A General Service Air Access

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

MONTHLY RATES AND CHARGES

Year-Round Residential – R2

Service Charge	$	16.45
Energy Charge First 1,000 kWh	$/kWh	0.0775
Energy Charge Next 1,500 kWh	$/kWh	0.1033
Energy Charge All Additional kWh	$/kWh	0.1300

Seasonal Residential – R4

Service Charge	$	27.80
Energy Charge First 1,000 kWh	$/kWh	0.0775
Energy Charge Next 1,500 kWh	$/kWh	0.1033
Energy Charge All Additional kWh	$/kWh	0.1300

General Service Single Phase – G1

Service Charge	$	27.95
Energy Charge First 6,000 kWh	$/kWh	0.0868
Energy Charge Next 7,000 kWh	$/kWh	0.1150
Energy Charge All Additional kWh	$/kWh	0.1300

General Service Three Phase – G3

Service Charge	$	35.00
Energy Charge First 25,000 kWh	$/kWh	0.0868
Energy Charge Next 15,000 kWh	$/kWh	0.1150
Energy Charge All Additional kWh	$/kWh	0.1300

Street Lighting

Energy Charge	$/kWh	0.0860

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

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Standard A Residential Road/Rail

Energy Charge First 250 kWh	$/kWh	0.5096
Energy Charge All additional kWh	$/kWh	0.5822

Standard A Residential Air Access

Energy Charge First 250 kWh	$/kWh	0.7691
Energy Charge All additional kWh	$/kWh	0.8418

Standard A General Service Road/Rail

Energy Charge	$/kWh	0.5822

Standard A General Service Air Access

Energy Charge	$/kWh	0.8418

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection/Disconnection/Load Limiter/Reconnection – if in Community	$	65.00