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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

September 17, 2012

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

Dear Ms. Walli:

EB-2012-0137 - Hydro One Remote Communities Inc. 2013 Revenue Requirement and Rates Application – Application and Prefiled Evidence

The Hydro One Remote Communities' Application and Prefiled-Evidence seeking approval of the 2013 revenue requirement and customer rates for the distribution and generation of electricity to be implemented on May 1, 2013, have been submitted using the Ontario Energy Board's Regulatory Electronic Submission System. The confirmation of successful submission slip is provided with this letter. It is also our intention to post electronic copies of the Application and supporting evidence on the Hydro One's regulatory web page. In addition, one copy is being provided for public access at Hydro One Remote Communities' Service Centre at 680 Beaverhall Place, Thunder Bay, P7E 6G9.

Hydro One Remote Communities' points of contact for service of documents associated with this Application are listed in Exhibit A, Tab 2, Schedule 1.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

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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 21 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 2013 revenue requirement and customer rates for the distribution and generation of electricity.

3. Remotes seeks approval of a revenue requirement of $52,284 thousand for the Test Year 2013, of which $17,260 thousand is proposed to be recovered through customer rates, $514 thousand from other revenues, leaving $34,510 thousand to be recovered from Rural and Remote Rate Protection (RRRP).

4. Remotes seeks approval to recover the December 31, 2013, forecast balance in the RRRP Variance Account and the forecast balance in the IFRS Transition Costs Account through RRRP rates. These balances of $819 thousand would be added

to the $34,510 thousand for recovery from all electricity users in the grid-connected part of the Province. Remotes is requesting the $35,329 thousand in RRRP to be established effective January 1, 2013.

5. Remotes seeks approval to retain the RRRP Variance Account to ensure that the business maintains its breakeven model. 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.

7. This application seeks approval for the establishment of new geographically remote grid-connected customer rates.

8. This Application also seeks approval for cost increases related to the inclusion of the geographically remote grid-connected communities of Cat Lake and Pikangikum in Remotes' service territory. The inclusion of new communities was identified as an upcoming cost pressure in the 2005 and 2008 submission. Agreements to include these communities in Remotes' service territory are being discussed between the communities and Remotes, subject to approval and agreement with the federal department of Aboriginal Affairs and Northern Development Canada ("AANDC"). Remotes intends to file a separate submission with the Board for approval to the change its service territory but the rates and specific costs to serve these community are included in this submission for the 2013 Test Year.

9. 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.

10. 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.

11. 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.

12. 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:

Ms Anne-Marie Reilly
Regulatory Coordinaqtor - 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
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Telephone: (416) 345-5913
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b) The Applicant's counsel:

Mr. Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

Mailing Address:	15th Floor, North Tower 483 Bay Street Toronto, ON M5G 2P5 M5H 3M7
Telephone:	(416) 345-6305
Fax:	(416) 345-6972
Electronic access:	Mengelberg@HydroOne.com

DATED at Toronto, Ontario, this 17 day of September, 2012.

HYDRO ONE NETWORKS INC.

By its counsel,

ORIGINAL SIGNED BY MICHAEL ENGELBERG

Michael Engelberg

SUMMARY OF APPLICATION

Hydro One Remote Communities ("Remotes") is an integrated generation and distribution company licensed to generate and distribute electricity within 21 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 business described above and on methodology and principles set out in the Board Filing Requirements for Transmission and Distribution Applications issued November 14, 2006 and updated June 28, 2012. The application is based on a forward-looking 2013 test year.

Several issues have converged that are expected to change Remotes' business and increase Remotes' required work program over the next five years: increased development, including proposed grid connections for many communities in the far north; federal funding constraints and a focus on building northern transmission infrastructure that will delay generation upgrades within Remotes' existing service territory; and the addition of currently grid-connected geographically remote communities to Remotes' service territory.

Taken together, these issues pose a significant transitional challenge. The communities' isolation means that when the generating plant reaches its capacity, no new electrical load can be connected to the distribution system. Curtailing the connection of new houses and other community buildings can result in lower levels of customer satisfaction and a deterioration in service reliability and, if frustrated community members construct and connect unauthorized services to the distribution systems, can pose a serious risk to public safety.

Delays to generation upgrades have and will continue to increase Remotes' work programs as aging assets need to be maintained, repaired and replaced. Continued high fuel prices increase the cost of generation and also increase the cost to transport staff, material and equipment.

Remotes has implemented several strategies to mitigate the impact of cost pressures and improve productivity, including improved coordination of work and flights to transport staff and equipment; more competitive fuel supply contracts; improved planning and purchasing processes to maximize winter road usage; improved customer collections; and customer-focused conservation initiatives and station efficiency standards. These efforts are ongoing and are planned to be continued in the 2013 Test Year.

In 2010 the Ontario Government amended the *Electricity Act, 1998* (the "Electricity Act") to require Remotes to serve grid-connected communities in accordance with government regulation. This change gives geographically remote communities that are currently connected to the grid and those considering a connection the option of being served by an established electricity distributor. Two communities, Cat Lake and Pikangikum, have now requested service agreements with Remotes. This Application seeks to establish rates for geographically remote, grid-connected customers and seeks approval for the costs and revenues associated with incorporating additional customers into Remotes' service territory. The inclusion of these communities has added approximately $3,083 thousand to revenue requirement. Remotes intends to file a separate submission with the Board for approval to amend its Licence to include these communities in its service territory.

This Application seeks to establish a new revenue requirement of $52,284 thousand, which reflects the increases in fuel and operating costs, while also incorporating the above noted productivity improvements. The Board of Directors of Remotes and Hydro One Inc. have approved the 2012 business plan on which this Application is based.

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 Rate Protection for these customers and requires that Remotes charge rates that are not based on the cost of service.

For the 2013 Test Year, Remotes is proposing to increase rates to the average customer in its service territory by 3.45%, the average increase for grid-connected customers approved by the Board in 2011.

Remotes is requesting approval to increase the annual level of Rate Protection in 2013 to $34,510 thousand. This increase is due to the increase in the required work program, increased fuel prices and the increase in number of customers.

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 forecast to be in a deficit position by the end of 2012. Remotes is requesting that recovery of this balance be added to the amount to be recovered through RRRP rates. Remotes is also requesting the recovery of the IFRS Transition Costs Variance Account. Together these recoveries will result in $35,329 thousand to be funded through RRRP rates. Remotes is also requesting to retain the RRRP 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' 2013 Test Year Revenue Requirement of $52,284 thousand ($17,260 to be collected through customer rates).
- Approval of associated customer rate increase of 3.45%.
- Approval to establish Rural and Remote Rate Protection to off-set the revenue requirement at $34,510 thousand as well as the forecast balance in the regulatory accounts of $819 thousand for a total RRRP for 2013 of $35,329 thousand.
- Approval for new geographically remote Grid-connected customer rates.
- Approval to retain the Rural and Remote Rate Protection Variance Account.

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, and updated on June 28, 2012. The proposed revenue requirement and rates included in this Application have been prepared on the basis of a forward-looking 2013 test year. This submission also includes information for a 2012 bridge year, historical information for 2010 and 2011, and historic Board-approved information for 2009. Given that Remotes' previous Cost of Service rate submission was based on a 2009 test, there is a four 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 $52,284 thousand: $17,260 thousand from its customers (3.45% rate increase over 2012 rates) and $34,510 from the Rural and Remote Rate Protection (RRRP) fund for the 2013 test year. Calculation of the revenue requirement appears in the evidence at Exhibit E1, Tab 1, Schedule 1.

Remotes' Operations, Maintenance and Administration ("OM&A") expenditures have been determined on the basis of an examination of required work programs to ensure that appropriate and cost-effective solutions are implemented. A description of Remotes' planning process is provided at Exhibit A, Tab 14, Schedule 1. The proposed OM&A expenditures are $44,199 thousand and include $24,067 thousand for diesel fuel required to generate electricity. Service to the grid-connected communities of Cat Lake and Pikangikum is expected to increase Remotes' customer base in 2013 by approximately 500 customers or 14% over the December 2011 customer base of 3,533. This growth in customers and an associated growth in the distribution maintenance work program is expected to increase OM&A costs by $3,083 thousand.

The overall proposed OM&A expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability as well as to repair, maintain and replace aging assets. These expenditures are itemized at Exhibit C2, Tab 2, Schedule 1 and discussed in written direct evidence at Exhibit C1, Tabs 1 and 2.

Remotes' proposed Rate Base of $41,090 thousand is discussed at Exhibit D1, Tab 1, Schedule 1.

Remotes has calculated working capital based on the formula-based methodology described in the Board's Filing Guidelines for Transmitters and Distributors issued June 28, 2012. 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.

Depreciation expense for Remotes' submission for the 2009 revenue requirement was based on the methodology in an independent study conducted by Foster Associates in 2006. Foster Associates completed a new Depreciation Study for Remotes Communities in support of its 2012 application. The study can be found at Exhibit C1-04-01 Attachment A. Depreciation expense $3,317 has been determined based on this study. These costs are described in written evidence at Exhibit C1, Tab 4, Schedule 1 and shown in detail in C2, Tab 5, 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 $2,713 thousand in the 2013 Test Year. Land Assessment and Remediation is discussed in Exhibit C1, Tab 4, 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, AANDC 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 AANDC, 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 14, Schedule 2. Remotes is forecasting total capital expenditures of $6,135 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.

Remotes receives less than 1% of its revenues from external sources ($514 thousand in 2013). External revenues are discussed at Exhibit E3, Tab 1, Schedule 1.

Rural and Remote Rate Protection for customers in Remotes' service area is currently set at $27,549 thousand per year. Remotes is requesting to increase annual RRRP revenue subsidies to $34,510 thousand.

In accordance with standard regulatory practice, Remotes has incurred prior costs for which it is requesting approval in this submission. A total of $747 thousand is forecast to be recorded at December 31, 2012 in the Rural and Remote Rate Protection Variance Account, primarily related to increased diesel fuel costs and required maintenance. Remotes is proposing to recover the $747 thousand in the 2013 test year. Remotes is also proposing to recover the $72 thousand balance in the IFRS Transition Costs Variance Account resulting in a RRRP amount of $35,329 thousand. Remotes' submission regarding these account balances and proposed disposition appears at Exhibit F1, Tab 1, Schedule 1.

SUMMARY OF REMOTES BUSINESS

1.0 INTRODUCTION

Remotes is an integrated generation and distribution company licensed to generate and distribute electricity within 21 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 8, 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 a leading remote community generation and distribution utility measured on performance in safety, environment and customer loyalty".

1.2 Corporate Mission

"We are a remote community electrical generation and distribution company focused on customer satisfaction and on using management systems to achieve operational excellence."

1.3 Corporate Values

We value:

- Safe work environment
- Customers and community relationships
- Environmental sustainability
- Consistent, fair, treatment of customers and staff
- Financial responsibility and accountability
- Business integrity
- Employee engagement
- Innovation and continuous improvement

2.0 REMOTES' BUSINESS ENVIRONMENT

Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, 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.

The communities served by Remotes are isolated and are scattered across the far north of the Province. Thirteen 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.

Industry, government and First Nations are currently examining the potential for the development in the remote north, including the development of a transmission grid. In 2010, the Ontario Government amended the *Electricity Act, 1998* (the "Electricity Act") to require Remotes to serve grid-connected communities in accordance with government regulation. The decision to permit Remotes to serve these customers was made to give geographically remote communities that are currently connected to the grid and those considering connecting to the grid the option of being served by an established electricity distribution company and in anticipation that these customers will qualify for rate protection if served by Remotes. Two such communities (Cat Lake First Nation and Pikangikum First Nation) have requested service from Remotes, and Remotes is seeking to establish rates for these geographically remote grid-connected customers in this Application.

Remotes inherited Ontario Hydro's obligations to provide electricity to off-grid communities, which were originally negotiated with the federal and provincial governments. Under these arrangements, the federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government, through AANDC, remain in place. These Agreements specify that Remotes is responsible for funding ongoing operation and maintenance of the system and that AANDC 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, AANDC devolved its responsibility for community infrastructure to First Nation communities. AANDC 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.

In 2011 AANDC informed Remotes that no funding for generation upgrades was included in its 2012-2016 capital plan due to funding constraints. In 2012, AANDC informed Remotes that the funding constraints were continuing and generation capital would not be included in the 2013-2017 capital plan. Upgrades are currently required in three communities and are expected to be needed in seven communities over the next five years. As a result, Remotes will not be able to connect new customers in communities where generation has reached its limits. As a result of the delays to planned upgrades, Remotes' capital and maintenance work programs must increase in order to meet safety, environmental and reliability standards.

3.0 DISTRIBUTION

Remotes operates 19 isolated distribution systems to serve the 21 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 233 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. Diesel generation is currently the prime source of electricity within the communities. Remotes also owns and operates two run-of-the-river mini-hydroelectric 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 57 diesel generators in service, ranging in size from 65kW to 1250kW. 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 (now known as “Clean Start”). Remotes’ 2003 report received the “Best New Submission” award; and since then, each annual submission has been awarded "Gold Champion" status.

6.0 GOVERNMENT REGULATION AND REMOTE COMMUNITY RATES

Remotes serves approximately 3,500 customers. Most customers within Remotes 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), also through capital contributions and Remote Rate Protection (RRP). RRP funding is currently set at $27,549 thousand per year. This amount is funded through a $0.0011/kWh charge to all grid-connected customers in Ontario that is set by the Ontario Energy Board to fund rate protection in rural and remote areas of the province.

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' current customers are shown in Exhibit G1, Tab 1, Schedule 1.

NOTICES OF MOTION

To be filed when available.

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 and revised on June 28, 2012.

Hydro One Remotes Distribution Application follows the format used in the previous Distribution Rates proceeding, which was well received by the Board and intervenors, and incorporates improvements made to the filing format. Remotes' Application satisfies the Filing Requirements and Handbook requirements except where it was not practical or appropriate to do so based on previous comments and direction from the Board, or as a result of specific government regulation.

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.

Exemptions from the *Ontario Energy Board Act, 1998*

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 by 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 is 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 7, Schedule 1, Attachment 1.

2.0 COMPLIANCE WITH LICENCE AND OEB FILING REQUIREMENTS

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:

- 2013 test year;
- 2012 bridge year;
- 2009, 2010 and 2011 historical years;
- 2009 Board-approved historical year.

3.0 RATE BASE

The Filing Requirements, past direction from the Board, and a number of specific government regulations influence the determination of Remotes' rate base and associated capital costs, as well as influencing the rate base information provided in the Application.

3.1 Depreciation Rates

Remotes 2013 Revenue Requirement includes the impact of newly proposed depreciation and amortization rates based on a new depreciation study conducted in 2011 by Foster Associates, found in Exhibit C1, Tab 4, Schedule 1.

3.2 Working Capital Allowance

Remotes' calculation for working capital is consistent with the formula described in the 2006 Electricity Distribution Rate Handbook and is filed in Exhibit D2, Tab 4, Schedule 1.

3.3 Interest Rates for Construction Work in Progress

The interest rate used for construction work in progress (CWIP) reflects the adoption of United States generally accepted accounting principles (US GAAP) per the Board's decision in EB-2011-0427. Under US GAAP, a utility capitalizes interest on qualifying capital programs and projects using its effective rate of its outstanding debt used to finance the capital expenditures made, unless the regulator requires the use of a specific allowance for funds used during construction rate (AFUDC). Consistent with its decisions in EB-2008-0408, effective January 1, 2012, no AFUDC is specified for use by Remotes. Prior to 2012, an AFUDC was 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, 2009 to 2011 historical years reflect the average quarterly prescribed interest rate. The construction work in progress evidence for the historical years, bridge year, and test year is filed in Exhibit D2, Tab 3, Schedule 3.

3.4 Capital Projects and Programs

Details for all capital projects and programs that exceed $261 thousand in net capital costs (0.5% of revenue requirement) are provided in Investment Justification Documents (IJDs). The IJDs for these projects and programs are filed at Exhibit D2, Tab 2, Schedule 3.

3.5 In-Service Additions

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 2013 test year, 2012 bridge year and 2009- 2011 historical years is filed in Exhibit D2, Tab 2, Schedule 4.

4.0 COST OF CAPITAL

Remotes' cost of capital is based on a 100% debt financing structure, 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 capital.

5.0 OPERATING (OM&A) COST OF SERVICE

Remotes' OM&A evidence has been filed on a USofA basis. Information for the 2013 test year, 2012 bridge year, and 2011 historical year is filed at Exhibit C2, Tab 2, Schedule 1.

6.0 OPERATING REVENUE AND REVENUE SUFFICIENCY/DEFICIENCY

The revenue sufficiency/deficiency for 2013 Remotes is shown through the calculation of the annual RRRP, in exhibit G1, Tab 1, Schedule 3.

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 1) and generation license (Attachment 2) 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.

Ontario

Electricity Distribution Licence

ED-2003-0037

Hydro One Remote Communities Inc.

Valid Until

December 23, 2023

Original signed by

____

Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: December 24, 2003
Date of Amendment: June 1, 2004
Date of Amendment: December 16, 2009

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

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1 Definitions

In this Licence:

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

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

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

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

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

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

"**Licensee**" means Hydro One Remote Communities Inc.

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

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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.

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code.

5.2 The Licensee shall:

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

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

6 **Obligation to Sell Electricity**

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.

7 **Obligation to Maintain System Integrity**

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.

8 **Market Power Mitigation Rebates**

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

9 **Distribution Rates**

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.

10 **Separation of Business Activities**

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.

11 **Expansion of Distribution System**

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.

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.

12 **Provision of Information to the Board**

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.

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

13 **Restrictions on Provision of Information**

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.

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:

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

14 **Customer Complaint and Dispute Resolution**

14.1 The Licensee shall:

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

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

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

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

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

15 Term of Licence

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

16 Fees and Assessments

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

17 Communication

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.

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

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

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

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

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

18 Copies of the Licence

18.1 The Licensee shall:

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

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

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 6.1 of this Licence.

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
21 Marten Falls (operated by the Licensee, owned by Marten Falls First Nation)

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 6.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

1. The entire Retail Settlement Code

2. The entire Standard Supply Service Code

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

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

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

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

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

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

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

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

3. Pass Through of Rebate

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

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

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

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

ONTARIO POWER GENERATION INC. REBATES

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

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

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

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

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

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

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

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

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

3. Pass Through of Rebate

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

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

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

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

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	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
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Toronto, ON M4P 1E4	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, 44
Ontario.

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

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

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

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, 52
Ontario.

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

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

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, 56
Ontario.

DocID: OEB: 12V9K-0

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

LETTERS BETWEEN PIKANGIKUM FIRST NATIONS AND MINISTRY OF ENERGY

Ministry of Energy
Office of the Minister
4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie
Bureau du ministre
4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

MAR 23 2012

MC-2012-814

Chief Jonah Strang
Pikangikum First Nation
P.O. Box 323
Pikangikum ON POV 2L0

Dear Chief Strang:

Thank you for your January 19, 2012, letter regarding Pikangikum First Nation's connection to the provincial electricity grid. I understand that your community has participated in discussions with Hydro One Remote Communities Inc. (RemoteCo) about this matter, as well as your community's interest in having RemoteCo assume operation of the local distribution network.

As a first step to the transfer of operational responsibilities, both RemoteCo and Pikangikum would be required to work together to address outstanding issues relating to the Pikangikum distribution system, including liabilities from past environmental contamination, assessment of asset conditions, outstanding arrears from when Ontario Hydro operated the system and transfer of asset ownership.

Both parties would also be required to engage Aboriginal Affairs and Northern Development Canada (AANDC) to enter into an agreement on roles and responsibilities regarding the operation of the Pikangikum distribution system, including AANDC capital funding support, land and access rights and continued commitment to support Standard "A" rates (should your community remain part of this rate structure) through existing federal electrical energy cost subsidies or alternative funding sources. Resolution of these matters is prerequisite to the Provincial regulatory changes that the government may initiate to enable RemoteCo to assume operation of the Pikangikum distribution system.

I encourage you to continue discussions with RemoteCo on transferring operational responsibilities. I am providing Myles D'Arcey, President and Chief Executive Officer of RemoteCo, with a copy of our correspondence to ensure that he is apprised of your request.

Should you have any further questions, please feel free to contact John Whitehead, Assistant Deputy Minister of Regulatory Affairs and Strategic Policy at the Ministry of Energy, at 416-325-6544.

Sincerely,

Chris Bentley
Minister

c: Myles D'Arcey, RemoteCo

DRC-2012-257

Pikangikum First Nation

P.O. Box 323
Pikangikum, ON P0V 2L0
Tel No.: 807-773-5578 / 773-5588
Fax No.: 807-773-5324

JW DRC

PC - Pikangikum First Nations asks for ministry assistance in setting up discussion with Hydro One Remote about operation of distribution network

S - Aboriginal Issues

January 19, 2012

Honourable Chris Bentley
Ministry of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario M7A 2E1

RECEIVED
CORRESPONDENCE UNIT
JAN 27 2012
MINISTRY OF ENERGY & INFRASTRUCTURE

RE: Pikangikum First Nation Connection to the Provincial Electricity Grid

Dear Minister Bentley

As you are aware Pikangikum First Nation is constructing a power line that will connect our community to the provincial transmission grid at Red Lake. This line is of critical importance to the future development of our community. The line will allow the development of infrastructure projects that at present cannot be completed because of the outdated and unreliable diesel generation system. These include constructing new housing, sewer and water to existing and new homes, a new school, businesses including a hotel and laundry and a new band office.

Pikangikum First Nation has successfully operated their own distribution system, with their utility Eshkotay Wayab Corporation since 1998. The changes in the energy market and the fiduciary and regulatory requirements under the distribution code have made it extremely difficult, if not impossible, for utilities of this type to continue to operate.

Pikangikum has moved forward on the planning and construction of the transmission line into Pikangikum on the basis that Hydro One Networks would be assuming ownership and operation of the transmission line. In discussion with Hydro One Networks, Hydro one Remote Communities Inc, has been designated the subsidiary that would operate the distribution network in Pikangikum First Nation.

It is our understanding, the Government of Ontario establishes Hydro One Remote Communities Inc.'s service territory by Regulation. As the gridline project is now at a crucial stage in development, Pikangikum First Nation requests that the Minister of Energy ask Hydro One Remote Communities Inc. to enter into discussions with Pikangikum First Nation (and Aboriginal Affairs and Northern Development Canada) to assume operations of the distribution network in Pikangikum once the grid connection takes place. Pikangikum First Nation and Hydro One Remote Communities Inc. will work to negotiate an operating agreement agreeable to all parties and that can be forwarded to you and the Ontario Energy Board for review and eventual approval. We look forward to Hydro One Remotes visiting Pikangikum to present the proposed rates and charges and conditions of service.

Thank you for your consideration in this matter, If you have any questions please do not hesitate to contact us.

Meegwetch

Chief Jonah Strang
Pikangikum First Nation

LETTERS BETWEEN CAT LAKE FIRST NATIONS AND MINISTRY OF ENERGY

CAT LAKE FIRST NATION
GORDON OOMBASH MEMORIAL BUILDING
2 BACK ROAD WEST
CAT LAKE, ONTARIO
P0V 1J0

PESHEWESAHEKNIK
NETUM ANESHENAPEK
(807) 347-2100
FAX (807) 347-2116

June 7, 2012

The Honourable Chris Bentley
Minister of Energy
900 Bay Street, 4th Floor
Toronto, ON
M7A 2E1

Dear Minister :

Cat Lake First Nation is a remote community located approximately 320 kilometers NW of the Town of Sioux Lookout in Northwestern Ontario. Cat Lake is situated in the provincial riding of Kenora - Rainy River and presently has 420 residents and band members living on-reserve.

A gold mine located 70 kilometers to the SW of Cat Lake ceased operations in the late 1990's. The community saw this as an opportunity to be connected to the provincial electrical grid which had supplied power to the mine site. The Department of Indian and Northern Affairs (INAC) was supportive of a project to extend the line connection to Cat Lake via a new 27.6 kV line connecting to the 115 kV line at the mine site. Cat Lake Power was formed to own and operate the transmission line that connected to the provincial grid system that runs between Ear Falls and Pickle Lake.

Cat Lake Power operated from 2001 to 2006. A forest fire in 2005 destroyed some of the transmission assets of the company. This event coupled with the loss of the INAC subsidy on federally funded assets in the community meant the First Nation owned utility company could not continue to operate. An application was submitted to the Ontario Energy Board (OEB) to discontinue transmission and distribution of electrical power to Cat Lake First Nation. The OEB then granted Hydro One Networks an interim distribution license to operate and maintain the assets of Cat Lake Power.

The interim order was approved by the OEB in July of 2006 and has been renewed every three months since that time. This interim order, which included a 62.5¢ / kWh interim rate for federally funded asset accounts, is excessive and the community cannot continue to pay this rate and remain financially viable. The situation is seriously hindering social and economic development programs in Cat Lake First Nation.

A meeting has been held recently with representatives from Hydro One Remote Communities Inc (HORCI) and the Department of Aboriginal Affairs & Northern Development to explore opportunities whereby Cat Lake First Nation could enter into a permanent servicing arrangement with Hydro One Remotes.

.... 2

At this time, I am formally asking the Minister of Energy to request that Hydro One Remote Communities Inc negotiate with the Cat Lake Band Council on a permanent servicing agreement for the transmission and distribution of electrical power to our community. If you have any questions or require any additional information concerning this matter, you can contact me at any time at telephone number 807-347-2100.

Sincerely,

Matthew Keewaykapow
Cat Lake Band Chief

cc Mr. Kraemer Colter, Hydro One Remote Communities Inc.
Ms. Linda Churchley, Department of Aboriginal Affairs & Northern Development.
Ms. Sarah Campbell, M.P.P. for Kenora - Rainy River Riding.

CAT LAKE FIRST NATION
GORDON OOMBASH MEMORIAL BUILDING
2 BACK ROAD WEST
CAT LAKE, ONTARIO
P0V 1J0

PESHEWESAHEKNIK
NETUM ANESHENAPEK
(807) 347-2100
FAX (807) 347-2116

June 7, 2012

Mr. Kraemer Colter
Managing Director
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON
P7E 6G9

Dear Mr. Colter :

The Cat Lake Band Council is very appreciative of the efforts of Mr. Bob Shine and yourself to pursue a permanent servicing arrangement between Hydro One Remote Communities Inc and Cat Lake First Nation. The Community of Cat Lake is presently serviced by Hydro One Networks on an interim distribution license that was approved by the Ontario Energy Board in July of 2006.

This interim order, which included a 62.5¢ / kWh interim rate for federally funded asset accounts, is excessive and the situation is seriously hindering social and economic development programs in Cat Lake First Nation. The community cannot continue to pay this excessive rate and remain financially viable. At this time, the Cat Lake Band Council is urgently requesting that further discussions be held with Hydro One Remote Communities Inc. on the issue of electricity rates and the conditions of servicing the residents and businesses of Cat Lake First Nation.

The Cat Lake Band Council would like to negotiate a permanent servicing agreement for the transmission and distribution of electrical power to the community. I have attached a Band Council Resolution resolving to pursue a permanent servicing arrangement with Hydro One Remote Communities Inc. If you have any questions or require any additional information concerning this request, you can contact me at any time at telephone number 807-347-2100.

Sincerely,

Matthew Keewaykapow
Cat Lake Band Chief

cc Ms. Linda Churchley, Department of Aboriginal Affairs & Northern Development.
Ms. Sarah Campbell, M.P.P. for Kenora - Rainy River Riding.

Indian and Northern Affairs Canada
Affaires indiennes et du Nord Canada

Chronological No. - N° consécutive
Site Reference No. — N° de référence du dossier

BAND COUNCIL RESOLUTION
RESOLUTION DE CONSEIL DE BANDE

NOTE: The words "from our Band Funds" "capital" or "revenue", whichever is the case, must appear in all resolutions requesting expenditures from Band Funds.
NOTA: Les mots "des fonds de notre bande" "capital" ou "revenu" selon le cas doivent paraitre dans toutes les résolutions portant sur des dépenses à meme les fonds des bande.

					Cash free balance – Solde disponible	
The council of / Le conseil de	CAT LAKE FIRST NATION				Capital Amount / Compte capital	$
Date of duly convened meeting / Date de l'assemvlée dument convoquee	D-J: 0 7	M: 0 6	Y-A: 1 2	Province: ONTARIO	Revenue Amount / Compte revenu	$

DO HEREBY RESOLVE:
DECIDE, PAR LES PRESENTES:

WHEREAS: Cat Lake Power discontinued the transmission and distribution of electrical power to Cat Lake First Nation in 2006.

WHEREAS: The Ontario Energy Board then granted Hydro One Networks an interim distribution license to operate and maintain the assets of Cat Lake Power.

WHEREAS: The interim distribution license included a 62.5 ¢ / kWh interim rate for federally funded asset accounts.

WHEREAS: This 62.5¢ / kWh rate is excessive and Cat Lake First Nation cannot continue to pay this rate and remain financially viable. The situation is seriously hindering social and economic development programs in the community.

THEREFORE BE IT RESOLVED THAT:
Cat Lake First Nation Chief and Band Council pursue a permanent servicing arrangement with Hydro One Remote Communities Inc for the transmission and distribution of electrical power to the community.

Quorum: 3 / 4

(Chief - Chef)

(Councillor - Conseiller)
(Councillor - Conseiller)

Abigail Wesley
(Councillor - Conseiller)

(Councillor - Conseiller)
(Councillor - Conseiller)

(Councillor - Conseiller)

(Councillor - Conseiller)
(Councillor - Conseiller)

(Councillor - Conseiller)

FOR DEPARTMENTAL USE ONLY – RESERVE AU MINISTERE					
Expenditure - Depenses	Authority (Indian Act Section) Autorite (Aeticle de la Loi sur les Indian)	Source of funds Source des fonds ___Capital ___Revenue	Expenditures - Depenses	Authority (Indian Act Section) Autorite (Aeticle de la Loi sur les Indian)	Source of funds Source des fonds ___Capital ___Revenue
Recommending officer – Recommande par Signature		Date	Recommending officer – Recommande par Signature		Date
Recommending officer – Recommande par Signature		Date	Recommending officer – Recommande par Signature		Date

Canada

SERVICE AREA MAP

The attached map is a representation of Remotes' service territory. It is not a substitute for the written description in the licence. Remotes is licensed to serve 21 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
Marten Falls
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

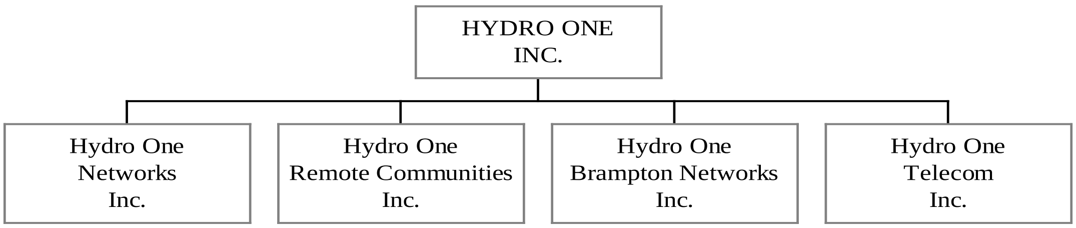
This schedule describes the current organization of Remotes' business, beginning with an overview of the parent company (Hydro One Inc.), a discussion about Hydro One Inc.'s subsidiary businesses, and a brief summary of Remotes' affiliates and related parties and transactions.

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. is the largest electricity transmitter and distributor in Ontario.

Figure 1 below shows Hydro One Inc.'s principal subsidiaries, each of which is wholly-owned and incorporated under the laws of Ontario. The business functions of Hydro One Inc.'s active subsidiaries are discussed in Section 3.0 of this Exhibit.

Figure 1
Hydro One Inc.



3.0 DESCRIPTION OF HYDRO ONE SUBSIDIARY BUSINESS ACTIVITIES

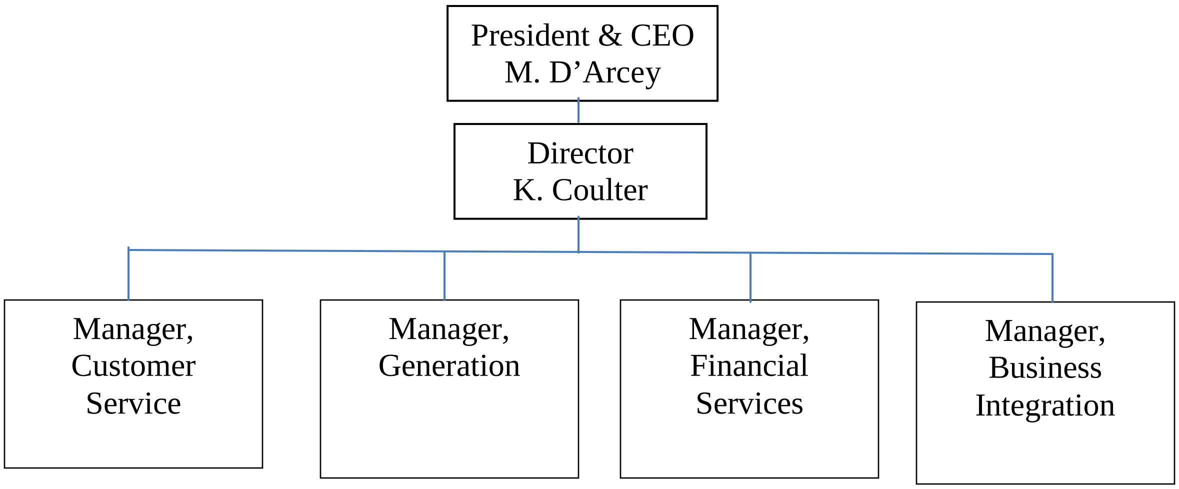
Hydro One Networks Inc. is the main subsidiary of Hydro One Inc. It is licensed by the Board (ET-2003-0035) to manage, own, operate and maintain Ontario's largest transmission network. It also holds a separate licence (ED-2003-0043) to manage, own, operate and maintain a distribution network in Ontario.

Remotes 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 include grid-connected and not connected to the transmission grid. It 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



3.1 Related Parties

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

a) The OEFC was established with the passage of the *Electricity Act, 1998*. Its primary responsibility is the management and retirement of Ontario Hydro's outstanding debt and other 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 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 provincial customer revenues from each LDC which includes the RRRP allocation.

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 AND CONTROL FRAMEWORK

1.0 OVERVIEW

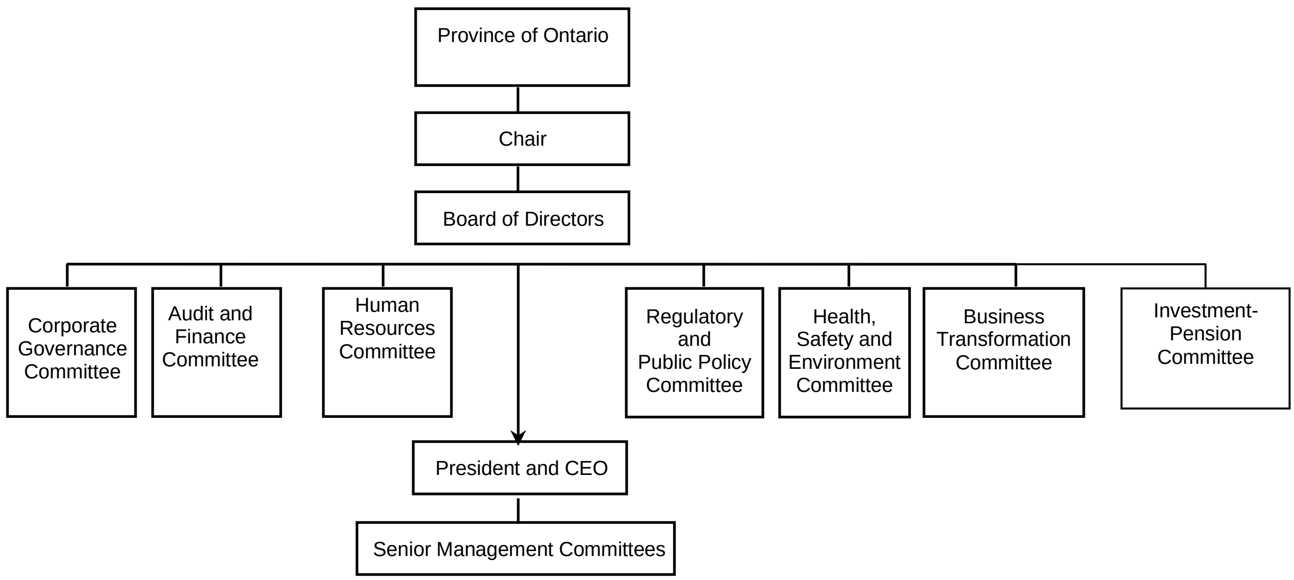
The Corporate Governance structure and Internal Control Framework of Hydro One Inc. provide reasonable assurance regarding Hydro One's effective and efficient operations, reliable financial reporting, and compliance with applicable laws and regulations. In the past few years, federal and provincial governments 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 (for example, Ontario's Bill 198).

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 objective and provide direction and accountability to senior officers to prudently and ethically manage the company's business and affairs, as well as the review and/or approval of mission, goals and business objectives, organizational authorities and business plans.

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

Figure 1
Hydro One Corporate Governance



2.1 The Hydro One Inc.’sBoard of Directors

The Board is responsible for the stewardship of the company and the supervision of management of the business and affairs of our company. The Board’s accountabilities and responsibilities include development of our company’s approach to corporate governance, the adoption of a strategic plan and oversight of risk management, as well as oversight of the company’s pension plan.

2.2 Committees of the Board of Directors

The Board has established various committees to address specific areas and responsibilities. However, the Board retains its oversight function and ultimate responsibility for all matters delegated to committees. The Committees of the Board are the Corporate Governance Committee, Audit and Finance Committee, the Human Resources Committee, the Regulatory and Public Policy Committee, the Health, Safety and Environment Committee, the Business Transformation Committee and the Investment-Pension Committee.

2.2.1 Corporate Governance Committee

The Corporate Governance Committee acts as the nominating committee of the Board and recommends director candidates, committee assignments, director compensation and corporate governance policy for Committees and the Board as a whole. The Committee reviews the general and specific criteria applicable to candidates to be considered for nomination to the Board, as well as an annual review of the mandates of 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 and reviewing Board effectiveness. The Committee is composed of independent directors.

2.2.2 Audit and Finance Committee

The Audit and Finance Committee is mainly responsible for overseeing the integrity of accounting policies and financial reporting, internal controls, auditing practices, financial risk exposures, financial compliance and ethics policies for Hydro One Inc. and its subsidiaries. Specifically, the Committee makes recommendations regarding financial objectives and plans and financial risk management strategies of the company. It is also accountable for reviewing and recommending to the Board for approval interim and annual audited consolidated financial statements; management discussion and analysis disclosures; and financial statements in debt securities offering documents and other related matters. In addition, the 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, specific complaints brought forward under the Code of Business Conduct. All members of the Committee are independent and financially literate.

2.2.3 Human Resources Committee

The Human Resources Committee's responsibilities, include reviewing the appropriateness of current and future organization structures, succession plans for corporate and divisional officers and conducts an annual review of the Code of Business Conduct. The Committee also reviews and approves base salary levels, base salary funding increases and funding for short term incentives. The Committee is composed of independent directors.

2.2.4 Regulatory and Public Policy Committee

The Regulatory and Public Policy Committee monitors the company's compliance with regulatory requirements and related risks and seeks to ensure that management is effectively managing those risks. The Committee is also responsible for reviewing management's regulatory proposals for transmission and distribution rate applications, as well as the status of outstanding applications. The Committee further identifies, assesses and provides advice to the Board on public affairs issues that may have a significant impact on the company. The Committee is composed of a majority of independent directors.

2.2.5 Health, Safety and Environment Committee

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

2.2.6 Business Transformation Committee

The Business Transformation Committee is responsible for assisting the Board of Directors in its oversight responsibility on matters related to the company's Cornerstone Project The Committee also assists the Board of Directors in fulfilling its oversight responsibility in all matters related to the Smart Grid and Continuous Innovation Strategy. In 2010, the Committee's mandate was further amended to include oversight responsibility for all matters related to the planning, development and implementation of major transmission system or distribution projects including the projects described in the Corporation's Green Energy Implementation Plan. The Committee is composed of independent directors.

2.2.7 Investment-Pension Committee

The Investment-Pension Committee's primary function is to assist the Board of Directors in fulfilling its oversight responsibilities in all matters related to the Hydro One Pension Plan, including the Hydro One Pension Fund. The Committee is composed of independent directors.

3.0 SENIOR MANAGEMENT COMMITTEES

Prudent decision-making and business transparency are supported by three key senior management committees: Executive Committee, Management Pension Committee, and Disclosure Committee.

3.1 Executive Committee

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

3.2 Management Pension Committee

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

3.3 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 securities regulatory requirements in Canada. The committee meets quarterly to review consolidated 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 integrity and 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 U.S. Committee of Sponsoring Organizations. 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 and must be complied with by all staff. The Code of Business Conduct requires all management employees 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. Lastly, individual performance contracts of management employees are intended to capture the understanding between a manager and a direct report as to the results expected and the means by which such performance results will be achieved.

"Risk Assessment" involves the identification and analysis by management of the key risks to achieving the company's business objectives. Such an assessment is performed, at least, annually, and 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. Risk assessment extends to individual investment decisions through the Project and Program Approval Process (see Exhibit A, Tab 14 Schedule 2). This process assesses whether any proposed solutions for a specific operational need will achieve a level of residual risk acceptable to senior management and the company's 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 that management's objectives are achieved and risk mitigation plans are carried out. Policies and procedures exist to govern annual, monthly and day to day operations at the business unit and local levels. Each revised policy has an issue date and last review date and are available on an internal web site. More information on Hydro One Inc.'s policies may be found in Exhibit A, Tab 13, 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 authorities are governed by 'Guiding Principles', the Code of Business Conduct, and policies and procedures. The approval of the business plans and budgets establish authorized spending levels.

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 set 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 14, Schedule 1.

The Executive Authorities Register (EAR) delegates authorities from the Board to senior management. Organizational Authority Registers (OARs) exist at subsidiary and business unit levels to delegate authorities from senior management to business unit and local levels.

The Inergi outsourcing agreement further provides approvals assigned by Hydro One Inc.'s to Inergi LP for specific transactions and spending levels.

"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. Communication occurs to all staff from the Executive Vice President and Chief Financial Officer and from the Vice President, Corporate Controller with respect to new or changed policies and procedures. Communications on various internal control matters also occur regularly. And, as noted previously, policies and procedures can be found on internal websites at most locations or are available in other formats.

"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.

Management provides assurance with respect to internal controls and the validity of financial statements. This includes information on 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. Management also 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 and every other line of business is required to conduct a detailed review of financial results by comparing operating results to budgets and responding to variances. 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 financial 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, compliance testing of key financial activities is performed.

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 9, Schedule 3). Internal Audit uses a risk-based audit approach for prioritizing audits and performs audits of areas of highest risk based on an annual program approved by the Hydro One Board's Audit and Finance committee. 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 Hydro One's 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.

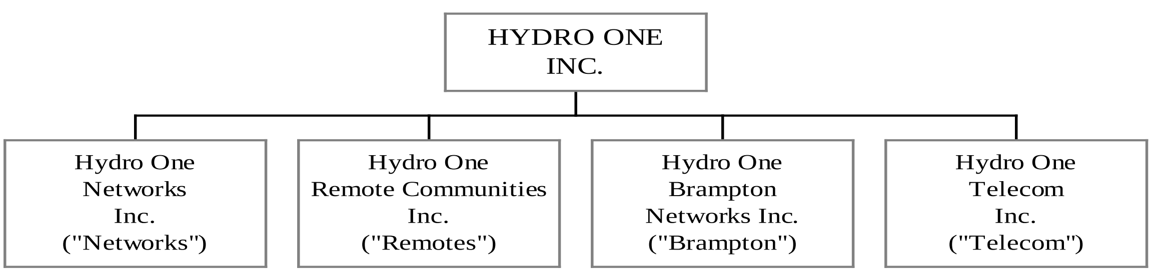
AFFILIATE SERVICE AGREEMENTS

1.0 INTRODUCTION

In accordance with the Affiliate Relationships Code (“ARC”), when Hydro One Networks Inc. (“Networks”) Transmission 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 affiliates are displayed in the corporate organization chart in Exhibit A, Tab 9, Schedule 1 and repeated in Figure 1 below for convenience.

This exhibit does not include Transmission Connection Agreements, Connection and Cost Recovery Agreements, Agreements for Licensed Occupancy of Power Distribution Poles, or any agreement involving the purchase or delivery of power between Networks and its affiliates. Such transactions are regulated separately by the Board and hence do not constitute a form of affiliate contract, as contemplated in section 2.3.1 of the ARC.

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 then incorporated into legal agreements with commercial terms and conditions, then reviewed and approved by each company's CEO or other accountable officer. Two of the agreements (Appendices A and B), 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 Networks and its affiliates are listed below, in Table 1, which identifies the service provider and recipient, and briefly describes the services.

Table 1
Service Level Agreements – 2012

Services Provider	*Services Recipient(s)*	*Description of Services*
Hydro One Inc. (Appendix A)	Networks[1] 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.

[1] Hydro One Inc. also provides certain assets to Hydro One Networks for its use.

Services Provider	***Services Recipient(s)***	***Description of Services***
Networks (Appendix B)	Hydro One Inc. Remotes Telecom 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, 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*** – provides services related to human resource and labour relations, protection of assets, Cornerstone support, information management, leadership and consultation support related to First Nations and Metis communities and corporate communications. ***d) Telecommunications-related Services*** – Field and engineering, logistics, corporate, construction, telecommunication and information technology services. ***e) Other Services*** – Customer services operation and information management services.
Networks (Appendix C)	Remotes	***CEO / President services*** – Administrative oversight, provision of strategic direction and advice, and advocacy of the services recipient's position regarding operational and budgetary issues.
Networks (Appendix D)	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, and engineering and construction services.
Networks (Appendix E)	Remotes	***Supply Chain Services*** – Implementation of demand planning, management and procurement, process development, data management and warehousing.
Remotes (Appendix F)	Networks	***Metering and Lines Services –*** Metering/Technician work including smart meter change-outs, line layout and update of emergency site plans.

3.0 TERMS AND CONDITIONS

In accordance with the ARC, the agreements describe the nature of, and the fees payable for, the services they contain. This includes 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 and utility operation and maintenance services from its affiliates as well as the provision by Remotes of metering and lines 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 product or use of asset to an affiliate, the utility shall charge no less than the greater of (i) the market price of that service, product, resource or use of asset and (ii) the utility's fully-allocated cost to provide that service, product, resource or use of asset. In purchasing a service, resource, product or use of asset from an affiliate, a utility shall pay no more than the market price for that service, product, resource or use of asset. Where no market exists, a utility shall charge no less than its fully-allocated cost to provide the service, product, resource or use of asset, and shall pay no more than the affiliate's fully-allocated cost to provide the service, product, resource or use of asset.

The annual fees payable to Networks by its affiliates for certain common administrative and corporate services for the years 2012 and 2013 and the corresponding applicable items are as follows:

Table 2
Fees Payable to Networks for Services Provided

FEES PAYABLE BY REMOTES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS: (in $Thousands)		
Services	**Remotes**	
General Counsel and Secretary Services • **2012** • **2013**	217 222	• Law • Corporate Secretariat • Regulatory Affairs
Financial Services • **2012** • **2013**	260 263	• Corporate Controller • Treasury • Tax • Decision Support • Internal Audit and Risk Management
Corporate Services • **2012** • **2013**	267 274	• Human Resources • Labour Relations • Communications • External Relations • Corporate Security • First Nations & Metis Relations • Information Management
Telecom Services • **2012** • **2013**	128 118	• Telecom Services
Transfer Price Charges for HONI Assets • **2012** • **2013**	0 180	Service Level Agreement will be prepared in 2013.
Other Services • **2012** • **2013**	375 366	Inergi: • Customer Support • Finance • Settlements • Human Resources • IT
CEO/President Services • **2012** • **2013**	80 80	CEO/President for Remotes; please see Appendix C.

FEES PAYABLE BY REMOTES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS: (in $Thousands)		
Services	**Remotes**	
Utility Operation Services • **2012** • **2013**	 936 929	Not classified as Corporate Common Services; please see Appendix D and Exhibit C1 Tab 3 Schedule 1 page 2.
Supply Chain Services • **2012** • **2013**	 77 77	Not classified as Corporate Common Services; please see Appendix E.
Totals • **2012** • **2013**	 2,340 2,329	

The annual fees payable by Remotes to Hydro One Inc. for certain common administrative and corporate services and payable by Remotes to Hydro One Telecom Inc. for telecommunications services, for the years 2012 and 2013 are as follows:

Table 3
Fees Payable by Remotes for Services Received

FEES PAYABLE BY REMOTES FOR SERVICES TO BE RECEIVED FROM HYDRO ONE INC.: (in $Thousands)			
Services provided by Hydro One Inc.	**2012**	**2013**	
General Counsel & Secretary	23	23	• Corporate Secretariat • Corporate Management
President / CEO / Chairman Services	18	18	• President/CEO Office • Chair • Board
Chief Financial Office Services	9	9	• CFO Office
Totals	50	50	

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 business 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. Such information includes information relating to a smart sub-metering provider, wholesaler, consumer, retailer, or generator. The agreements also include security safeguards to be adhered to by the party receiving such 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 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.

THIS AGREEMENT made in duplicate this 17th day of January, 2012 (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. Each electronic journal transfer amount shall include HST (as this term is defined in clause 4.0(a)(iv) below) calculated at the rate applicable at the time such journal transfer is recorded in the books of the Services Provider. 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.

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;
- (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) it is a HST registrant in good standing under the *Excise Tax Act* (Canada), and that its HST registration number is 869994731RT0001. For the purposes of this Agreement, HST means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

(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 document entitled "Information Security Policy" (SP 0908 R1) dated January 17, 2012 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
(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:

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**
TCT8
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay Street,

Toronto, Ontario M5G 2P5

Attention:	**Ryan Lee**
	TCT 8
Telephone:	416-345-5158
Telecopier:	416-345-6833

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

Attention:	**Sandy Struthers**
	TCT15
Telephone:	416-345-6140
Telecopier:	416-345-5695

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

Attention:	**Marc Villett**	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: George Carleton
Title: VP, Supply Chain Services
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.

Name: Peter Gregg
Title: EVP, Operations
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Laura Formusa
Title: President & CEO

I have authority to bind the corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

R. Fernandes
Name: Remy Fernandes
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	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)	850.0	23	9	18
President / CEO / Chairman Services	3,349	18	28	33
Chief Financial Office Services (including Strategic Financial services)	756	9	23	32
Totals	**4,955.00**	**50.0**	**60.0**	**83.0**

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.

<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.

THIS AGREEMENT made in duplicate this 17th day of January, 2012 (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, with the exception of Hydro One Inc., 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 purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

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 document entitled "Information Security Policy" (SP 0908 R1) dated January 17, 2012 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 8
Telephone: 416-345-6698
Telecopier: 416-345-6356

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

Attention: **Ryan Lee**
TCT 8
Telephone: 416-345-5158
Telecopier: 416-345-6833

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

Attention:	**Sandy Struthers**
	TCT 15
Telephone:	416-345-6140
Telecopier:	416-345-5695

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

Attention:	**Marc Villett**
Telephone:	(905) 452-5501
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: George Carleton
Title: VP, Supply Chain Services
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: Laura Formusa
Title: President & CEO
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Sandy Struthers
Title: Executive Vice President and Chief Financial Officer
I have authority to bind the corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Name: Remy Fernandes
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	87.0	217.0	87.0	174.0
Financial Services	74.0	260.0	342.0	390.0
Corporate Services	-	267.0	253.0	26.0
Telecommunication Services	-	128.0	279.0	-
Other Services	-	375.0	1,031.0	-
Totals	**161.0**	**1,247.0**	**1,992.0**	**590.0**

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.

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 five main areas:

- Human Resources / Labour Relations – 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, benefit plans and incentive plans.
- Business Architecture – provision of information systems support for Cornerstone Phase 1 and 2 as well as the management of legacy tools to support real time operations.
- Information Management – provision of computer and applications management support, internal telecommunications management, IT capital projects and IT strategy management and Inergi applications support management.
- Corporate Security – provision of advice, guidance and investigative support services to ensure the protection of assets and optimize the reliable delivery of electricity.
- First Nations & Métis Relations – provision of leadership and consultation support to address issues with First Nations & Métis communities.
- 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 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:

- 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.

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.

THIS AGREEMENT made in duplicate this 17th day of January, 2012 (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. 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 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 purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

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 document entitled "Information Security Policy" (SP 0908 R1) dated January 17, 2012 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,
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 8
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
North Tower, 14th Floor B13
Toronto, Ontario M5G 2P5
Attention: **Rob Berardi**
Telephone: (416) 345-4277
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: Joseph Agostino
Title: Officer
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Maureen Wareham

Name: Maureen Wareham
Title: Officer
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.

<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.

Execution Copy

THIS AGREEMENT made in duplicate as of the 1st day of January, 2012 (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. 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 the following types of 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:

- Forestry services
- Work Methods and Training services
- Metering services
- Provincial Lines services
- Safety services
- Fleet services
- Environmental services
- Engineering Services
- Flight safety services
- Distribution Planning Technical services
- Joint Use services
- Health and Safety Services

3.0 DEFINITIONS

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

(a) "**Agreement**" means this Agreement between the Services Recipient and the Services Provider and shall include Schedules "A", "B", "C", "D", "E" and "F" attached hereto and any amendments to the body of this Agreement and to the Schedules.

(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.

4.0 FEES PAYABLE

(a) The price for the performance of the Services described in Schedule "C" hereto shall be as specified in the said Schedule "C" and shall include any sales and use taxes as may be applicable. 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 2012-2013 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 2012-2013 hourly and fleet rates from the Services Provider.

The parties agree that the 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 or by direct time reporting through Hydro One Inc.'s payroll system.

(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 to be made for nil consideration for purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

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 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;

(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 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.

6.0 PERFORMANCE OF THE SERVICES

(a) **Access to Site:** For each type of Services to be performed, the Services Recipient shall provide the Services Provider with an opportunity to visit and examine the site at which the said type of Services are to be performed prior to commencement of the performance of the said type of Services. Upon commencement of performance of the said type of Services, 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 said type of Services are to be performed 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 document entitled "Information Security Policy" (SP 0908 R1) dated January 17, 2012 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.

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

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

(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 Agreement.

(d) **Constructor:** The parties acknowledge and agree that the Services Provider shall be the "Constructor" of the Services performed 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 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 Agreement. If the work is not in accordance with the requirements of this Agreement, 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 Agreement, the Services Recipient shall pay the cost of examination and restoration. No payment by the Services Recipient shall constitute an acceptance of any portion of the Services which are not in accordance with the requirements of this Agreement.

(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 Agreement 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 Agreement, 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 Agreement. 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.

(j) **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 including work already in progress in accordance with this Section.

If either party desires a change in the work described in the Services, it shall complete and submit to the other party, a Change Notification Form (the "CNF") in the form attached hereto as Schedule "B". The CNF shall identify the reasons and impact (cost and schedule) of the change. The other party shall respond to the CNF 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 CNF and the executed CNF shall be attached to this Agreement.

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 2012/2013 hourly rates as may be amended pursuant to this Agreement and the CNF 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.

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 CNF 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 Agreement 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 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 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 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, 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 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 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 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:** 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 this Agreement 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 Agreement.

10.0 INSURANCE

The Services Provider shall maintain in full force and effect during the term of this Agreement 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 and all 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 this Agreement. 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 this Agreement 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 this Agreement, 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 this Agreement. 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 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 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 Agreement.

12.0 AUTHORIZED REPRESENTATIVES

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

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay St.
South Tower, 8th Floor
Toronto, Ontario
M5G 2P5
Attention: Una O'Reilly
Telephone: (416) 345-6698

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor
Toronto, Ontario
M5G 2P5
Attention: Deb Vines
Telephone: (416) 345-5592

All correspondence, reports, documents and/or other communication concerning this Agreement, the Schedules attached hereto or any of the Services shall be directed to the attention of the authorized representatives noted above. Any notice permitted or required to be given hereunder 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 Agreement 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 Agreement, 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 Agreement, 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 Agreement nor any the rights and obligations hereunder may 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 Agreement 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 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 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, 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 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 Agreement and Schedules "A", "B", "C", "D", "E" and "F", the provisions of the former 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 Agreement 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 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.

21.0 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 REMOTE COMMUNITIES INC.	**HYDRO ONE NETWORKS INC.**
Name: Peter Gregg	Name: Sandy Struthers
Title: Director	Title: Director
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 Schedule "C", 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 Schedule "C" (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 Schedule "C" (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 description of Services in Schedule "C" to the Agreement.

- 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 the Agreement. 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 Schedule "C" to the Agreement;
   - Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the 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 Services 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 Services 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 Schedule "C" to the Agreement;
(d) Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the 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"

CHANGE NOTIFICATION FORM (No. xxx)

Date issued: xx-xxx-xx

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

Schedule "C"

Description of Services

FORESTRY SERVICES:

A. Description of Services:

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

1. Upon the Services Recipient's request, perform condition assessments of the Services Recipient's distribution systems, and prepare a proposed multi-year forestry maintenance cycle for the Services Recipient.

2. Upon the Services Recipient's request, perform condition assessments of the Services Recipient's assets, and prepare cost estimates depicting at a minimum: labour hours and type (Technician, Supervisory, Maintainer, HH, etc.), TWE rates and requirements, material costs, board and lodging expenses, transportation costs excluding air charters, and applicable sundries in sufficient detail necessary for work scheduling and business planning purposes. As well, the amount of joint use right of way and associated clearing costs shall be identified by the Services Provider within the estimates.

3. Site monitoring of line clearing and/or brush control performed by third party contractors retained by the Services Recipient for servicing its rights of way in First Nation Communities as identified by the Services Recipient's representative. As required, the Services Provider shall clear lines and remove brush within the limits of approach to make it safe for First Nation Community contractors to clear lines and control brush outside the limits of approach.

4. Perform line-clearing in all communities within the Services Recipient's designated territory and brush control on all assets located on provincial land as identified by the Services Recipient. As well, from time to time as requested by the Services Recipient, the Services Provider will perform brush control activities on First Nation lands when the First Nation is unable to unwilling to perform the task to meet applicable standards.

5. Perform brush control measures including herbicide application where applicable in all station yards within the Services Recipient's territory.

6. Assist with the development of the line clearing and brush control specifications and standards necessary for negotiations with third party contractors and First Nations Administration.

7. Assist in providing notification of forestry services to communities and attaining necessary permissions from property owners or custodians.

8. Obtain various work permits such as cutting rights and stumpage fees on Crown Land or from companies with assigned cutting rights, fuel wood and stream crossing permits from the Ministry of Natural Resources, or transportation/crossing arrangements with the Canadian National Railway or Canadian Pacific Railway for the performance of the forestry services.

9. Provide forestry support for emergency line clearing and trouble calls.

10. Provide forestry support for line clearing and brush control as required for work driven by extensions, connections, betterments and upgrades to distribution facilities.

11. Provide documentation and support to enable the Services Recipient to obtain Purchase Service Agreements (PSA) with the Power Workers Union (PWU) for line clearing in First Nation communities, as well as, necessary sole source and procurement documentation.

12. Prepare and provide detail cost estimates of identified planned work to the Services Recipient by April 15, 2012 in order to facilitate business planning for the following year as may be needed. The Services Recipient shall identify the work to be estimated by March 1, 2012. Other estimates that may be required throughout the year and will be prepared and provided 15 days after the request is received by Forestry Services Scheduling.

13. The Services Provider shall prepare and provide necessary PSA and procurement documentation for First Nation brushing contracts by April 15, 2012. The Services Recipient will be responsible for managing and completing PSA negotiations with the PWU and approve procurement documents as it deems necessary.

14. The Services Provider shall complete 100% of the annual planned line clearing and brush control operations by December 15' 2012. The details of the annual plan will be discussed at a meeting between the Services Recipient's Customer Service Manager or delegate and the Services Provider's Forestry Superintendent - Northern Zone or Territory Manager delegate and shall be held before the end of February, 2012 where the parties will confirm activities and expectations for the year.

B. **Price and Terms of Payment**:

The Services Recipient shall pay the Services Provider for the forestry services on a time and materials basis in accordance with the wage schedules of the Services Provider.

The above fees payable excludes all airfares and lodging and contractual obligations as required under the collective agreement for the Services Provider's costs while working at the Services Recipient's facilities, which shall be paid directly by the Services Recipient. The Services Recipient will arrange and pay for the scheduling of charter flights to the Services Recipient's sites.

C. **Service Levels**:

The Services Provider shall report the following information in writing to the Services Recipient by December 15, 2012:

- Kilometers of line controlled / treated in each community
- Number of helicopter landing sites cleared
- Total actual cost of the forestry services in each community
- Instances of customer objection to use of herbicides and/or treatment of vegetation by any method; such customer disputes shall be resolved by the Services Recipient if resolution could not be attained through the Services Provider's regular procedures
- Detailed work completion reports of line clearing and brush control in each community upon completion of project.

WORK METHODS AND TRAINING SERVICES:

A. Description of Services:

The Services Provider shall provide the Services Recipient, as required by the Services Recipient, with the following services related to specific job procedures outlining sequence, tools, resources, safety precautions, and hazards relating to job tasks (collectively, the "Work Methods") and trades/technical training support for distribution lines, customer service and station maintenance trades in accordance with the specific terms and conditions noted therein:

1. **Training Delivery**
   - The Services Provider will provide requested trades training for the Services Recipient.
   - The Services Recipient will provide the names of all employees working for the Services Recipient on a continual basis (i.e. new employees/apprentices) to the Services Provider.
   - The Services Provider shall schedule the training in such manner so as to meet the Services Recipient's reasonable needs. In order for the Services Provider to meet these needs, the Services Recipient shall submit a "Request for Training" form 30 days in advance of the training requested, which form may be amended from time to time by the Services Provider. The "Request for Training" form is posted, and can be accessed, electronically at the Hydro One Plugin Website>HSE>Training>Forms (http://hydronet.hydroone.com/Pages/default.aspx).
   - The Services Recipient shall determine and notify the Services Provider as to whether or not training will be delivered in a centralized or decentralized manner.
   - The Services Recipient will also notify the Services Provider with as much time as possible in the event there is a need for Training course cancellation, but in any event no less than 10 Business Days' prior written notice. The Services Recipient acknowledges and agrees that if it does not provide the Services Provider with a minimum 10 Business Days prior written notification of training course cancellation, the Services Recipient will bear all costs that may have been incurred by the Services Provider for training development, scheduling, travel, and accommodations related to said training course.

The Services Provider and the Services Recipient shall comply with the following accountability matrix:

Accountabilities Matrix	
Task	**Accountability**
Approval of Course Content	Services Recipient
Course Participants	Services Recipient
Course Instructors	Services Provider
Course Scheduling	Services Provider
Development of Course Material	Services Provider
Quarterly Report of all training activities to Services Recipient	Services Provider

2. **Records Maintenance**
   - The Services Provider shall input all of the Services Recipient's training data into the Services Provider's centralized database within ***(10) ten*** Business Days after the Services Provider's receipt from the Services Recipient of the completed "Training Record Input Form", which form may be amended from time to time by the Services Provider. The "Training Record Input Form" is posted, and can be accessed,

electronically at the Hydro One Plugin Website>HSE>Training>Forms (http://hydronet.hydroone.com/Pages/default.aspx).

- The training record maintained by the Services Provider will include all legislated, Corporate-mandated and trade specific training. Other topics will be included at the request of the Services Recipient.
- All training records/information shall be accessible via the Hydro One Learning Management System (view only – HOLMs on the Hydro One Plugin Website - (http://hydronet.hydroone.com/Pages/default.aspx) by the Services Recipient.

3. Training Material Development

- The Services Recipient will identify to the Services Provider the skill sets required, including all mandatory-training requirements. The Services Recipient shall inform the Services Provider requests to develop new training material by completing the "WM&T Creation of New Projects" Form, which form may be amended from time to time by the Services Provider. The "WM&T Creation of New Projects" Form is posted, and can be accessed, electronically at the Hydro One Plugin Website>HODS>SP-0699 (http://hydronet.hydroone.com/Pages/default.aspx).
- The Services Provider will produce and maintain all course materials as directed by the Services Recipient, including a list of Subject Matter Experts participating and/or completing the project.
- The modification of training packages will be developed by the Services Provider within a timeframe agreed to by both parties, after the Services Provider's receipt of signed terms of reference from the Services Recipient. The Services Provider shall ensure that the modifications shall include such items as new equipment, legislative changes, performance requirements and new procedures as requested by the Services Recipient.

4. Communication

- The Services Recipient's training contact will be identified to the Services Provider by no later than October 30, 2012 and will speak with the Services Provider's representative identified in the body of the Agreement on a quarterly basis to review the Services Provider's performance of the work methods and training services as required by the Services Recipient. The Agenda for these quarterly meetings will be developed by the Services Recipient and forwarded to the Services Provider.
- A course catalogue and availability of training courses for the coming year will be provided by the Services Provider to the Services Recipient on an ongoing basis. This is currently available to the Services Recipient through HOLMs.

5. Work Methods and Procedures Development

- The Services Provider will provide assistance to the Services Recipient in the development of new Work Methods and/or procedures as required by the Services Recipient.
- The development and assessment of new work procedures/tools will be a joint effort between the parties based on a terms of reference document which shall be provided by the Services Recipient to the Services Provider with timeframes for completion established by both parties.
- The Services Provider will provide the Services Recipient with access to all work procedures and bulletins developed by the Services Provider.

B. Price and Terms of Payment:

The Services Recipient shall pay the Services Provider for the Work Methods services on a time and materials basis in accordance with the wage schedules of the Services Provider.

In addition, the Services Recipient will pay the cost of all material, travel and per diem costs incurred by the Services Provider related to the provision of these work methods and training services. The scheduling of charter flights to the Services Recipient's sites will be arranged and paid for by the Services Recipient. The Training Specialist/officer's time includes development and scheduling and shall be paid by the Services Recipient. The Training Manager's costs, including managing these work methods and training services, shall be paid by the Services Recipient in accordance with the hours in the chart above.

C. Service Levels:

- Training schedules/course availabilities for all required training (which are currently provided/available through the Services Provider's HOLMS database) shall be issued by the Services Provider within 90 days after the date first written above.
- The Services Provider shall provide the Services Recipient with post-course assessments of trainee accomplishment/performance to ensure employee competencies in areas trained.
- The Services Provider shall ensure that 95% of the scheduled training shall be provided to the Services Recipient prior to expiry of the term of the Agreement.

METERING SERVICES:

A. Description of Services

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

- manage the Services Recipient's annual Meter Reverification and Sample Program : issuing work orders to the Services Recipient's field forces for meter change-outs of recalled (due meters), seal expired (overdue), sample and failed meters;
- verify/reverify and seal meters to meet the Services Recipient's field demand for meter change-outs;.
- manage physical meter inventory by maintaining adequate stock of metering equipment to meet the needs for annual meter reverification, new services, service upgrades and replacement of failed or defective/damaged meters;
- acquire / provide data to the Services Recipient as required by the Services Recipient to resolve meter disputes and customer complaints, including, as required, metering documentation and documentation about hardware;
- manage meter requirements for change-outs of reported damaged or defective meters (i.e. defective replacements) and disputed meters. The Services Provider shall issue meter equipment within 4 working days of a field request therefore from the Services Recipient;.
- maintain and track accurate meter and instrument transformer records in the Customer Service System in compliance with the requirements in the federal Electricity and Gas Inspection Act as amended;
- develop metering specifications/standards and provide engineering support to the Services Recipient;
- provide access to training and conferences for Remotes Metering and Distribution Engineering Technician and other Services Recipient staff;
- liaise with Canada Revenue Agency on behalf of the Services Recipient including with respect to audit +and metering installation reporting.

The Services Provider shall provide the Services Recipient with a written report by no later than December 15, 2012 wherein it shall specify the cost and accomplishments of the metering services provided by its personnel for the said year.

B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider a fee of $10,000.00 for the metering services

The parties acknowledge and agree that the payment terms are as specified in the Agreement.

C. Service Levels:

All metering services will be provided by the Services Provider in accordance with ISO 9001:2008 requirements.

PROVINCIAL LINES SERVICES:

A. Description of Services:

Demand Work and Trouble Repairs:

Subject to the Services Provider's availability of personnel and resources which shall be determined by the Services Provider in its sole discretion, the Services Provider shall, in accordance with the Services Recipient's request from time to time, maintain the Services Recipient's distribution system (which distribution system supplies customers in remote communities at voltages of less than 50kV) by providing the following activities, as may be requested by the Services Recipient:

- Customer connection/disconnection to/from the primary distribution system
- Trouble Call Response, power restoration and storm damage repairs
- Line layout, estimating and staking
- Service Layouts and Collections
- Power line maintenance, construction and repair
- Distribution system operation including application of the Work Protection Code
- Arc Facilities Management (ArcFM) technical trouble support

For the performance of the above-referenced provincial lines services, the Services Provider shall provide:

1. subject to staff availability, short duration release of up to a maximum of 2 Regional Line Maintainers (RLMs) to cover absence/augment crew size. The Services Recipient will contact the Services Provider (Customer and Business Service Manager) as soon as practical to identify the need for all resources;

2. trouble Call Response: provide work crew(s) from appropriate geographical locations (Thunder Bay, Ear Falls, Dryden, Kenora, Timmins) in response to customer trouble calls dispatched by either the Services Recipient's First Line Manager/Union Trades Supervisor lines or the Services Provider's Supervisor on call. Trouble Calls crews shall be provided by the Services Provider on short notice and are subject to availability;

3. subject to staff availability, Customer Demand Work: Provide work crew(s) from appropriate geographical locations (Thunder Bay, Ear Falls, Dryden, Kenora, Timmins) in response to customer connection/ minor line construction requests from the Services Recipient's First Line Manager;

4. subject to staff availability, Lines Technical Work: Provide an Area Distribution Engineering Technician, (ADET)/Metering Technician, or Line Technician for short duration work assignments upon request from the Services Recipient's First Line Manager;

5. respond to requests for distribution system technical services and engineering approval(s).

Planned Work:

The Services Provider will work with the Services Recipient's First Line Manager to include in the Services Provider's plans the availability and supply of personnel and resources to meet the requirements for planned work in the Services Recipient's service territory. The Services Provider shall, in accordance with the Services Recipient's work plans respond to the Services Recipient's requests, from time to time, to maintain the Services Recipient's distribution system (which distribution system supplies customers in remote communities at voltages of less than 50kV) by providing the following activities, as may be requested by the Services Recipient:

- Line layout, estimating and staking
- Service Layouts and Collections
- Power line maintenance, construction and repair
- Sentinel light installation, repair or removal
- Distribution system operation including application of the Work Protection Code
- Meter Installation and reverification and sample meter changes
- Processing requests for railway and water crossing approvals
- Joint Use Consultation/Technical support
- Technical services in support of the Hydro One distribution line standards
- Engineering approval(s) and updates to the Distribution line standards
- MDx (Distribution system) data collection training and assistance
- Training and technical support for implementation and maintenance of ArcFM.

For the performance of the above-referenced provincial lines services, the Services Provider shall:

1. include in the Services Provider's plans, and make available, staff for short durations (up to 6 weeks) release of up to a maximum of 2 RLMs to cover absence/augment crew size;

2. include in the Services Provider's plans, and make available, staff for short durations (up to 6 weeks) work crew(s) from appropriate geographical locations (Thunder Bay, Ear Falls, Dryden, Kenora, Timmins) in response to customer connection/ minor line construction, MDX data collection requests from the Services Recipient's First Line Manager;

3. include in the Services Provider's plans, and make available, staff for short durations (up to 6 weeks), Area Distribution Engineering Technician, (ADET)/Metering Technician and Line Technician upon request from the Services Recipient's First Line Manager;

4. respond to requests for distribution system technical services and engineering approval(s).

Supervision, Administration, Health and Safety

The Services Provider shall comply with the following supervision, administration, health and safety, and work management conditions in its performance of the provincial lines services:

1. All training, supervision and administration costs associated with staff on rotation shall be accounted for within the Services Recipient's work program. Core/mandatory training shall be scheduled within the regular work location whenever possible.

2. Whenever possible, the Services Provider will provide advice for all Lines and Technician training requirements. Also, whenever possible, the Services Provider will provide notification for all Lines and Technician training that will be delivered at the local Hydro One Thunder Bay office. It is agreed that the Services Recipient will pay for all costs incurred by its staff to attend this training. Costs associated per Services Recipient employee will be agreed to prior to the Services Recipient employee attending the training.

3. Health and Safety incidents involving crews under the Services Provider's direct supervisory control shall be the responsibility of the Services Provider's lines operations centres.

Transport and Work Equipment (TWE) Provision

1. The Services Recipient will provide TWE at all fly-in sites for types of work, i.e. Trouble Calls, other Line work, Technician work.

2. For demand work at road access sites, trouble calls and new connects, the Services Provider will supply TWE, the cost of which will be included in the fees payable by the Services Recipient.

3. For Technician work at road access sites, the Services Provider will supply TWE and the costs of TWE will be included in the fees payable by the Services Recipient.

B. Price and Terms of Payment:

Except as specifically provided herein, the following fees:

- At the end of each quarter of the Term, the Services Recipient shall pay the Services Provider for the Services provided by the Services Provider an amount equal to the greater of (i) $28,125.00 and (ii) the total of the amounts payable for each type of Service provided by the Services Provider during the said quarter.
- The amount payable at the end of each quarter as described in the foregoing bullet hereunder shall be exclusive of applicable taxes.

Demand Work and Trouble Repair

- Time and Materials including any required overtime.
- The Services Recipient pays for all costs associated with fly-in work.

Planned Work

- Time and Materials including any required overtime.
- The Services Recipient shall pay all incremental travel/overtime costs for the assignment of personnel from locations other than Thunder Bay for Lines, Technician and Customer Service personnel.
- In addition, the Services Recipient will pay the Services Provider's costs of the administration and reporting in respect of these provincial lines services, material, transport and work equipment, travel and per diem costs related to the provision of these provincial line services other than trouble call response services.

C. Service Levels:

Demand Work – 100% of requests shall be satisfied within 14 days' after receipt of the request
Service Level for Demand Work:
For short duration Line and Technician work – an email request will be provided by the Services Recipient to the Services Provider for all planned work assignments. Fourteen days prior written notice is required to be provided by the Services Recipient to the Services Provider for cancellation/withdrawal of staff/crews committed to short duration assignments. The Services Recipient may request personnel and resources of up to 2 RLMs and 2 Distribution Line/Metering Technicians.

Trouble Response – 24/7
Service Level for Trouble Call Response:
Subject to the immediately proceeding sentence, the Services Provider shall restore service to customer and/or community within 24 hours after receipt by the Services Provider of the Trouble Call from the Services Recipient. The Services Recipient acknowledges and agrees that during major storm events, the Services Provider's staff may not be available to meet the 24-hour response timeframe, however, staff not involved in emergency work will be dispatched immediately and other staff will be dispatched as soon as conditions allow.

Scope of Trouble Calls that will be responded to by the Services Provider:

- 24 calls/year
- Work is mainly transformer re-fusing and switch re-fusing
- Each call is typically 3-4 hours of work and 6-8 hours of travel

Planned Work

The Services Provider will meet with the Services Recipient's FLM quarterly and include the Services Recipient's personnel and resource needs in the Services Provider's personnel and resource planning and scheduling. In order to facilitate integration of resource requirements, a meeting will be held during the first quarter of the term with the Services Provider's Zone 7 contact person where the Services Recipient will make known all major planned work for the year. Planned work not identified during this meeting will be subject to staff availability; however, efforts will be made to accommodate and may include resourcing from other parts of the Province.

The Services Recipient's contact person for work assignments is First Line Manager (FLM) Customer Service/Lines and Scheduling.

The Services Provider's contact person for work assignments in Zone 7 is the Business Manager; for other Zones, it will be the Superintendent, his delegate or scheduling group as agreed by the parties. Special requirements, scheduling conflicts and service level performance concerns will be discussed with the respective Zone Superintendent.

SAFETY SERVICES:

A. Description of Services:

The Services Provider shall provide the Services Recipient with following services related to safety:

1. Incident Reporting

The Services Provider shall assist the Services Recipient's Line Management with the proper and timely notification of safety related incidents for:

- Corporate reporting requirements
- Workplace Safety and Insurance Board
- Ministry of Labour

2. Incident Investigation

The Services Provider shall provide assistance/leadership for the investigation of high MRPH (Maximum Reasonable Potential for Harm) incidents and other lower incidents as requested by the Services Recipient's Line Management, the scope of which activities shall include, but not be limited to, the following:

- Prepare an initial bulletin notice of incident occurrence
- Assist with the Terms of Reference for incident investigations
- Being an investigation team member/leader
- Review/present the final report of the incident investigations to the Services Recipient's Line Management
- Assist with the development of an action plan to implement investigation recommendations

3. **Health and Safety Management**

The Services Provider shall assist the Services Recipient's Line Management with the development and maintenance of the Services Recipient's Health and Safety Activities, in support of their Environmental Health and Safety Management System (EHSMS) which may include the following:

- conduct an annual review of the Services Recipient's EHSMS, provide analysis and make recommendations for improvements;
- identify Hydro One safety requirements and provide information/advice on legal and other requirements applicable to the Services Recipient's business;
- prepare/issue a quarterly newsletter of recent H/S legislative changes and developments affecting Remotes.

4. **Compliance Reviews**

In consultation with the Services Recipient's Line Management, coordinate and conduct an annual compliance review of the Services Recipient's legal and other requirements that pertain to health and safety. Where required, the Services Provider shall develop appropriate protocols for the evaluation of health and safety compliance, in accordance with the Services Recipient's EHSMS procedures. The Services Provider shall also prepare and provide to the Services Recipient a written report summarizing the findings of the compliance review within 3 weeks of the field visits.

5. **Miscellaneous Services**

The Services Provider shall:

- attend Safety Meeting presentations given by both parties and provide support on urgent items or significant rule and regulation changes
- provide Job Planning Assistance including site visits, upon request
- review quality of work process inspections performed by the Services Recipient and recommend improvements, upon request
- perform work process inspections upon request and provide results to the Services Recipient
- provide the Services Recipient with a monthly written report at the end of each month during the term of the Agreement wherein it will describe the costs and accomplishments of these miscellaneous services provided by its personnel for the said month.

B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider a fee not exceeding $50,000 for the safety services, based on actual time and expenses incurred, in accordance with the hourly rates referred to in the Agreement.

In addition, the Services Recipient will pay the cost of the administration and reporting in respect of the safety services, material, travel and per diem costs related to the provision of the safety services. The Services Recipient will arrange and pay for the scheduling of charter flights to the Services Recipient's sites.

C. Service Levels:

None.

FLEET SERVICES:

A. Description of Services:

The Services Provider shall provide the Services Recipient with the following fleet management, maintenance, repair and rental services relating to the use of transport and work equipment:

a) Inspections, maintenance and repair of fleet transport and work equipment. The identification and completion of minor repairs and maintenance (under $500.00) will be the Services Recipient's responsibility and at the Services Recipient's expense.

b) Supply of fleet licensing and provision of insurance as per Hydro One Inc. requirements.

c) Advise on fleet planning and acquisition as per the Services Recipient's evolving requirements. Increase or decrease of fleet compliment will be reviewed annually and fees paid adjusted accordingly.

d) Supply the current transport and work equipment complement for the fee specified,

e) Co-ordinate the replacement program including assistance with justifications for additions and replacements to current complement.

B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider the depreciation costs of the Services Recipient's vehicles and the Services Recipient's costs for fuel, labour and external repairs. The scheduling of charter flights to the Services Recipient's sites will be arranged and paid for directly by the Services Recipient.

C. Service Levels:

The Services Provider shall, on a monthly basis during the term of the Agreement, provide the Services Recipient with a written summary of the total fleet costs by transport and work equipment unit and a written monthly fuel usage report for any equipment, spare parts, material and fuel purchases made by the Services Recipient from the Services Provider using the fleet credit card.

ENVIRONMENTAL SERVICES:

A. Description of Services:

The Services Provider shall provide the Services Recipient with the following environmental services as required:

- Quarterly Legislative Review
- Compliance Reviews and compliance support
- Emission Calculations and verification
- Certificate of Approval Amendments
- Support for remediation projects
- Investigations of diesel fuel alternatives
- Waste Management support
- Emergency response support

B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider the cost of time and materials required to perform these services.

C. Service Levels:

All environmental services will be provided by the Services Provider in accordance with a jointly agreed work plan. Quarterly reviews of progress to be performed.

ENGINEERING SERVICES:

A. Description of Services:

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

Webequie DGS Project

- Modify contractor drawings and incorporate them into Meridian
- Make up connection and elementary wiring diagrams, mechanical layout and architectural drawings

Station Drawings

- Develop mechanical, civil and architectural templates for plant Station Standards
- Develop connection wiring and elementary wiring diagrams for switchgear design that resembles the standards used by the Services Provider
- Review Station drawings and adjusting them to the Services Provider's standards and save them into Meridian

Arc Flash calculation and administrative process

- Validate, review and advise the Services Recipient on battery and charger system standardization
- Validate, review and advise the Services Recipient on SCADA communications solutions
- Assist in the development of Distributed Generation Connection Requirements

B. Price and Terms of Payment:

The Services Provider shall pay to Services Recipient for thee engineering services on a time and materials basis.

C. Service Levels:

None.

<u>FLIGHT SAFETY SERVICES:</u>

A. Description of Services:

The Services Provider shall provide the Services Recipient with the following services related to flight safety:

1. Monitor all aviation occurrences between the Services Recipient and the commercial passenger charter companies with which it contracts, which occurrences shall include but not be limited to the following:

   - Accidents, incidents or occurrences as defined in GEN 3.3 of the Aeronautical Information Publication and the Canadian Aviation Regulations

   - Non-airworthiness defects (*cosmetic repairs*) and airworthiness defects (*that would result in the aircraft being grounded until repaired*)

   - Feedback from the Flight Evaluation Report *(internal report used to provide feedback from passengers and pilots to the Services Recipient to identify aircraft and contract problems*)

   - All incidents deemed to be High MRPH (*High Maximum Reasonable Potential for Harm*)

   - occurrences of a lesser risk, low MRPH, and occurrences handled at the Services Recipient's local operations level in Thunder Bay; the Services Provider shall track these occurrences and the Services Recipient when the number of these occurrences becomes of concern.

2. Assess, control and respond to occurrence reports.

3. Provide Team Lead/key resource for all High MRPH incident investigations.

4. Provide charter contract administration of all technical job specifications along with liaison representation with the Services Recipient's Superintendent of Operations and maintenance for new pilot interviews as well as current pilot presentations.

5. Assist with the planning of and participate in the annual Flight Safety Staff Meeting which shall be arranged by the Services Recipient at a date and time to be mutually agreed upon by the Services Recipient and the Services Provider. The Services Provider will arrange for its "Flight Safety Officer" to attend and present new and current information relevant to flight charter contracts and the aviation industry including a presentation of related flight safety information, approved pilot and aircraft lists, audit and monitoring results, and corrective action feedback.

6. Perform pre-award audits and provide a summary report on any fixed wing charter carriers prior to the award of any contract for passenger charter air service.

B. Price and Terms of Payment:

The Services Recipient shall pay to the Services Provider a fee of $10,000 for the Services.

In addition, the Services Recipient will pay the cost of the administration and reporting in respect of this Contract, material, travel and per diem costs related to the provision of the Services described in this Contract. The scheduling of charter flights to the Services Recipient's sites will be arranged and paid for by the Services Recipient.

C. Service Levels:

The Services Provider will report on a monthly basis the cost and accomplishment of the Services provided by its personnel.

DISTRIBUTION PLANNING TECHNICAL SERVICES:

A. Description of Services:

The Services Provider shall provide the Services Recipient with the following services related to distribution planning:

- conduct fuse co-ordination studies;
- carry out distribution system modeling;
- conduct short circuit/fault analyses;
- conduct tingle voltage studies;
- produce engineering drawings for unique situations/requirements;
- conduct voltage irregularity analyses;
- distribution Lines and Metering construction standards support;
- special distribution engineering standard support;
- GIS data maintenance and migration support;
- distribution design technology and tool support;
- distribution metering technical support;
- distribution lines technical support; and
- support with ESA Regulation 22/04.

B. Price and Terms of Payment:

The Services Provider shall pay to Services Recipient for thee engineering services on a time and materials basis.

C. Service Levels:

None.

<u>JOINT USE SERVICES:</u>

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 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.

B. Price and Terms of Payment:

The annual price for the performance of the Services for the Services Recipient shall be $15,000.00, exclusive of any sales and use taxes, as may be applicable.

C. Service Levels:

None.

HEALTH AND SAFETY SERVICES:

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 health and safety program:

(i) WSIB Claims Management

- support the supervisor in WSIB reporting and early and safe return to work;
- provide guidance and interpretation of WSIB policy and legislation to the Services Recipient's line management;
- manage the financial impact of the WSIB claim cost statement and submit monthly premium remittance the Workplace Safety and Insurance Board on behalf of the Services Recipient.

(ii) Care Management

- support the Services Recipient's sick leave program that deals with sick leaves greater than 5 days and that is medically supported;
- support (via the Services Provider's Disability Management Consultant, the affected supervisor and employee through a third party provider while the employee is absent from work due to a major medical absence with a view to assisting in providing the right care at the right time for the right outcome

(iii) Long Term Disability (LTD)

- provide the Services Recipient with LTD case management services including application assignment to LTD payroll and ongoing case management and rehabilitation activities through a third party provider

(iv) Audiometric Testing

- support the Services Recipient's supervisors to carry out an Audiometric Program through the Health, Safety and Environment Management System (HSEMS) that establishes the requirement to implement operational controls to minimize a health and safety risk

(v) Respiratory Screening Program

- support the Services Recipient's supervisors in determining how respirators will be managed at the Services Provider's premises

(vi) Ergonomic Assessments

- support the workplace parties through the Workstation or Vehicle Ergonomic Assessment process.

(vii) Physical Demands Analysis (PDAs)

- develop and maintain Physical Demand Analyses to assist with the Services Recipient's employees fitness to return to work

B. Price and Terms of Payment:

The annual price for the performance of the Services for the Services Recipient shall be $10,000.00 exclusive of any sales and use taxes, as may be applicable.

C. Service Levels:

None.

Schedule "D"

COMMERCIAL GENERAL LIABILITY INSURANCE CERTIFICATE
SUPPLY ONLY TRADES

Issued in favour:				
Insured:				
XXXXXXXXXXXXXXXXXXXXXX				
XXXXXXXXXXXXXXXXXXXXXX				
XXXXXXXXXXXXXXXXXXXXXX				
XXXXXXXXXXXXXXXXXXXXXX				
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 THE MASTER AGREEMENT**				
		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 of the Services, 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.

<u>Schedule "F"</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.

THIS AGREEMENT made in duplicate this 17th day of January, 2012 (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. 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 supply chain 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 $76,674.00, 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 purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

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 document entitled "Information Security Policy" (SP 0908 R1) dated January 17, 2012 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,
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 8
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
North Tower, 14th Floor B13
Toronto, Ontario M5G 2P5
Attention: **Rob Berardi**
Telephone: (416) 345-4277
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.	**HYDRO ONE REMOTE COMMUNITIES INC.**
Joseph Agostino	Maureen Wareham
Name: Joseph Agostino	Name: Maureen Wareham
Title: Officer	Title: Officer
I have authority to bind the corporation	have authority to bind the corporation.

Schedule "A"

DESCRIPTION OF SERVICES:

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

- demand planning;
- management and procurement;
- vendor and inventory management;
- process development;
- data management;
- warehousing;
- waste management; and
- investment recovery.

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.

THIS AGREEMENT made in duplicate this 17th day of January, 2012 (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. 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

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 2012-2013 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 2012-2013 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 purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

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 document entitled "Information Security Policy" (SP 0908 R1) dated January 17, 2012 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,
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 8
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
North Tower, 14th Floor B13
Toronto, Ontario M5G 2P5
Attention: **Rob Berardi**
Telephone: (416) 345-4277
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: Joseph Agostino
Title: Officer
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Maureen Wareham
Title: Officer
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
- update Emergency Site Plans

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

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.

HYDRO ONE INC. – ANNUAL REPORTS (2009, 2010 and 2011)

Attachment 1: Hydro One Annual Report 2009

Attachment 2: Hydro One Annual Report 2010

Hydro One Annual Report 2011 not yet available

ANNUAL REPORT 2009

Investing in Ontario's Energy Future

hydroOne

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 21 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. This business represents less than 1% of our total assets.

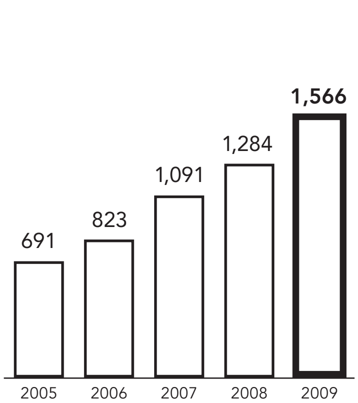
For more than 100 years, Hydro One has connected customers to safe, reliable and cost-effective electricity. Today, we are working to meet Ontario's energy needs for the 21st century.

Consolidated Financial Highlights and Statistics

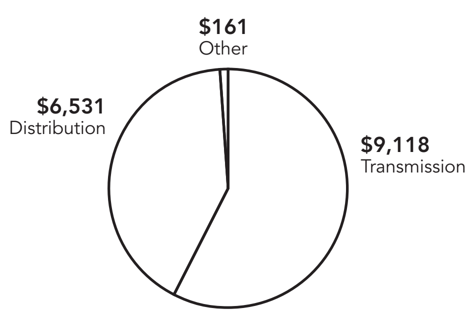
Year ended December 31 (Canadian dollars in millions)	**2009**	2008	$ Change	% Change
Revenues	**4,744**	4,597	147	3
Purchased power	**2,326**	2,181	145	7
Operating costs	**1,594**	1,513	81	5
Net income	**470**	498	(28)	(6)
Net cash from operations	**892**	1,052	(160)	(15)
Average annual Ontario 60-minute peak demand *(MW)*[1]	**20,798**	21,820	(1,022)	(5)
Distribution – units distributed to customers *(TWh)*[1]	**28.9**	29.9	(1.0)	(3)

[1] System-related statistics include preliminary figures for December.

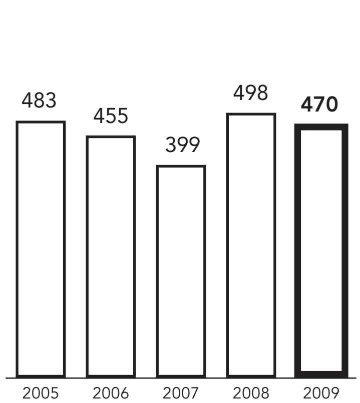
Capital Expenditures
(Canadian dollars in millions)



Total Assets
December 31, 2009 (Canadian dollars in millions)



Net Income
(Canadian dollars in millions)



Letter from the Chair

Fundamental to the Board's role is fostering a commercial culture that increases enterprise value while providing safe, reliable and cost-effective transmission and distribution of electricity.

James Arnett
Chair of the Board of Directors

As the Ontario Energy Board recently noted, Hydro One faces an operating environment that is turbulent and to some extent unknown. In this environment, the Company performed well in 2009.

I will leave it to the President and Chief Executive Officer to report on our results and financial metrics for the year.

Fundamental to the Board of Directors' oversight role is ensuring that Hydro One acts as a commercial enterprise and, to that end, fostering a commercial culture that increases enterprise value for the shareholder while providing safe, reliable and cost-effective transmission and distribution of electricity to Ontario's electricity users.

In 2008, the Board adopted a new strategic plan which emphasized this, and in 2009, the Board reviewed it and found it still appropriate.

Key to all of this is ensuring alignment of the organization with the Company's strategic objectives. To accomplish this, the Board has approved a corporate scorecard and short-term management incentives based upon performance measures derived from the corporate scorecard. The Human Resources and Public Policy Committee of the Board spent a lot of time and effort during the past year analyzing and refining the corporate scorecard and these measures. The resulting management compensation is described in detail in our Annual Information Form for 2009. The Board determined that of 13 corporate targets, 8 were met or exceeded and 5 were not and accordingly decided, in its discretion, on a 13% reduction from the overall maximum potential payout. On the other hand, the payouts were still significant, reflecting a good overall performance.

Another area where the Board spent more time and effort than usual was in its oversight of the pension plan, primarily by the Audit and Finance Committee. All aspects of the governance and management of the pension plan were reviewed in detail. Meanwhile, the sharp rebound in the financial markets from 2008 resulted in a significant improvement in the plan's position at year end.

In September 2009, the Board considered in detail, and then agreed to, a request from the Government of Ontario to proceed with the planning for a series of major transmission projects in support of the Green Energy Act (GEA). Management is working on the development of those projects. In December, the Company received

2010

Clean Energy Corridor
Construction of the Bruce to Milton Transmission Reinforcement Project will begin in 2010.

2X

Infrastructure
Over the past five years, Hydro One's work program has nearly doubled, principally to refurbish aging infrastructure.

Environmental Assessment approval for the Bruce to Milton Transmission Reinforcement Project, the largest transmission project by the Company in a generation. Construction of the transmission line will begin in 2010.

Meanwhile, the Company completed its largest-ever work program both in capital and OM&A. Indeed, over the past five years, the Company's work program has nearly doubled, principally to refurbish aging infrastructure, which is required quite apart from the GEA.

These major capital programs will require continued careful oversight of the Company's operating and financial situation. They will also require that we maintain the Company's strong credit ratings to facilitate the borrowing which will be increasingly required. The Audit and Finance Committee of the Board scrutinizes this from a financial perspective. In addition, the Business Transformation Committee will oversee all matters related to the planning, development and implementation of our GEA projects.

In conclusion, I believe that the Board of Directors performed well in its oversight role during 2009.

I want to thank management, all of our employees, and all my colleagues on the Board of Directors for their dedication and tireless efforts on behalf of both our customers and our shareholder.

James Arnett
Chair of the Board of Directors
Hydro One Inc.

Letter from the President and CEO

It's a pivotal time for Hydro One. Our customers rightfully expect a safe, reliable and cost-effective grid at a time when Ontario's energy sector is undergoing tremendous investment and change.

Laura Formusa
President and Chief Executive Officer

2009 was a year of moving forward for Hydro One. Our Company made progress on multiple projects, embraced new technologies and strengthened relationships as we focused on our core role as stewards of Ontario's electricity transmission grid and largest distribution system.

It's a pivotal time for Hydro One. Our customers rightfully expect a safe, reliable and cost-effective grid at a time when Ontario's energy sector is undergoing tremendous investment and change. Our strategy is guided by four key values: health and safety, stewardship, excellence and innovation. These values touch every initiative and inform every decision.

These values serve Ontario well as we continue with the largest program of infrastructure investment and renewal in more than two decades. The move to cleaner, decentralized power sources provides us with the opportunity to rethink our systems of transmission and distribution. Projects across the province are focused on improving the performance of existing assets, relieving internal congestion points and delivering new clean and renewable generation to Ontario homes and businesses. Hydro One is a key enabler of the Green Energy Act (GEA) and is developing an electricity grid that is modern, flexible and smart; one that will contribute to a better environment, and deliver clean, renewable power to and from growing communities.

Our smart meter program surpassed the key milestone of one million smart meters installed, with almost 750,000 meters communicating at a level capable of reliable meter reading. This is one of the largest smart meter deployments by a utility in North America. Our customers will begin to move to time-of-use pricing in 2010, with full transition expected in 2011.

Hydro One played a leadership role in the technical assessment and acquisition of the 1.8–1.83 GHz spectrum for Smart Grid applications. Our people were leaders in obtaining a dedicated communications spectrum for Smart Grid applications from Industry Canada – this was an enormous achievement which will pave the way to our smarter future.

In September, the Government of Ontario asked our Company to proceed with a series of transmission projects in support of the GEA. We began the planning work on several large projects in October and continued our planning of the Northwest Transmission Expansion Project.

In December, we received Environmental Assessment approval for the Bruce to Milton Transmission Reinforcement Project. The project involves constructing a new 180-kilometre double-circuit 500-kilovolt transmission line from the Bruce Power Facility to our Milton Switching Station and will enable the delivery of 1,700 MW of renewable generation identified in the area, as well as about 1,500 MW of power from refurbished units at the Bruce Power Facility. We expect to break ground on this project in the first half of 2010.

3,200
MW

Renewable Energy

We received Environmental Assessment approval for the Bruce to Milton Transmission Reinforcement Project that will enable approximately 1,700 MW of renewable generation identified in the area, as well as about 1,500 MW of power from refurbished units at the Bruce Power Facility.

1
MILLION

Smart Meters

Our smart meter program surpassed the key milestone of one million smart meters installed.

#1

Corporate Citizen

In 2009, Hydro One was named Canada's top corporate citizen by *Corporate Knights* magazine.

In 2009, *Corporate Knights* magazine named Hydro One as Canada's top corporate citizen. We were proud to receive that acknowledgement, but we take nothing for granted. I believe a company is not just measured by what they do, but also by how they do it. That's why we continue to focus on building strong relationships with First Nations and Métis communities, as well as all the communities in which we work and live.

We minimize our impact on the environment by examining every piece of our operations for improvement. This year's focus on our fleet of vehicles, which travel more than 100 million kilometres per year, included large initiatives like the introduction of Ontario's first hybrid bucket truck, a rigorous anti-idling and driver behaviour policy and the adoption of a vehicle right-sizing program to match the right-sized vehicle to the right task. Over the last year, we removed 525 metric tonnes of greenhouse gases through these and other initiatives.

Our partnerships with Ontario's institutions of higher learning are beginning to yield dividends with more and more qualified applicants helping Hydro One meet the human resource challenge we face. More than 30% of staff are eligible to retire within the next five years. We continued to invest in children's active play facilities in communities across Ontario through our PowerPlay program. While many corporate giving initiatives were scaled back this year, we continued to invest in the communities we serve.

From the engineers planning the future of Ontario's grid, to the line maintainers who climb poles in icy darkness, and everyone in between, I'd like to thank all Hydro One staff for giving their best every day. I'd like to thank the members of the management team for their tremendous contributions and the Board of Directors for their continued guidance. I believe by ensuring that everything we do reflects health and safety, stewardship, excellence and innovation, we will continue to deliver the electricity system that the great province of Ontario deserves.

Laura Formusa
President and Chief Executive Officer
Hydro One Inc.

Prudently managed and profitably operated, Hydro One has a strong track record for delivering value as well as for transmitting and distributing electricity.

Focused on Productivity

At Hydro One, we are always looking for ways to improve productivity. In 2009, we introduced two new rigorous performance metrics: Cost per Asset Value for transmission and Cost per Line Length for distribution. These two metrics allow us to do a better job of benchmarking our performance against industry peers and to better monitor our productivity on a year-over-year basis. In our first year using these metrics, we met our targets for both.

Other process changes in 2009 that also led to improved productivity, included:

– *Using the SAP schedule tool* to better monitor maintenance task cycles, which enabled us to reduce equipment time outages and to dispatch work crews more efficiently.

– *Launching a Customer Care initiative* that reduced the volume of billing exceptions requiring manual interventions. This initiative also focused on improving handling and tracking processes in order to reduce handling time, eliminate errors and cut costs.

– *Adopting a Strategic Sourcing Model* that enhanced our work program delivery by giving us better, more secure access to critical long-lead time materials.

Strong Financial Performance

Hydro One is focused on performance. As Ontario's largest electricity transmission and distribution company, our mission is to operate profitably, to create value for our shareholder and to be a safe, reliable and cost-effective transmitter and distributor.

In 2009, we met our financial targets with a net income of $470 million and revenues of $4,744 million. We paid $188 million in dividends to our shareholder, the province of Ontario, and $77 million in payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation.

In a challenging financial market, Hydro One kept its "A" credit rating, ensuring that we can continue to borrow money over the long term on a cost-effective basis. We also raised $1.15 billion in long-term financing, enabling us to meet the cash requirements for debt retirements and capital programs in an economical and timely manner.

Our success shows that Hydro One remains an attractive investment. It also highlights the benefits delivered by the Company's efforts to establish strong relationships with credit rating agencies, banks and potential investors.

$470 MILLION — Net Income for Fiscal Year 2009

$1.15 BILLION — Raised in Long-Term Financing

$188 MILLION — Paid in Dividends to the Province of Ontario

#1 — On *Corporate Knights'* Best 50 Corporate Citizens List

Noteworthy Achievements

Hydro One is helping to build a conservation culture within Ontario. We are also working to establish a corporate culture that values transparency and accountability, that celebrates diversity, and that supports employees at work and in the community.

In 2009, our efforts were rewarded with significant recognition.

In their annual listing of the country's best 50 corporate citizens, *Corporate Knights* magazine named Hydro One as Canada's Top Corporate Citizen. The magazine's rankings are based on a wide-ranging review of publicly reported environmental, social and governance indicators, including diversity, pension quality and health and board independence. In 2009, aboriginal relations were also weighed as an indicator.

> *"The ranked companies are doing the best job at fulfilling their end of the social contract and managing their specific environmental, social and governance performance when compared with their sector peers."*
>
> *Corporate Knights* magazine

Hydro One was also named one of the Top 90 Toronto Employers for 2010. After reviewing applications from more than 2,600 employers, Mediacorp Canada Inc. recognized Hydro One for supporting employees through ongoing skills training, and for its efforts to support employee involvement in the communities where they work.

In 2009, Hydro One met the challenge of providing reliable service while replacing end-of-life equipment within our system. We also helped to implement the Green Energy Act and did our part to secure Ontario's energy future.

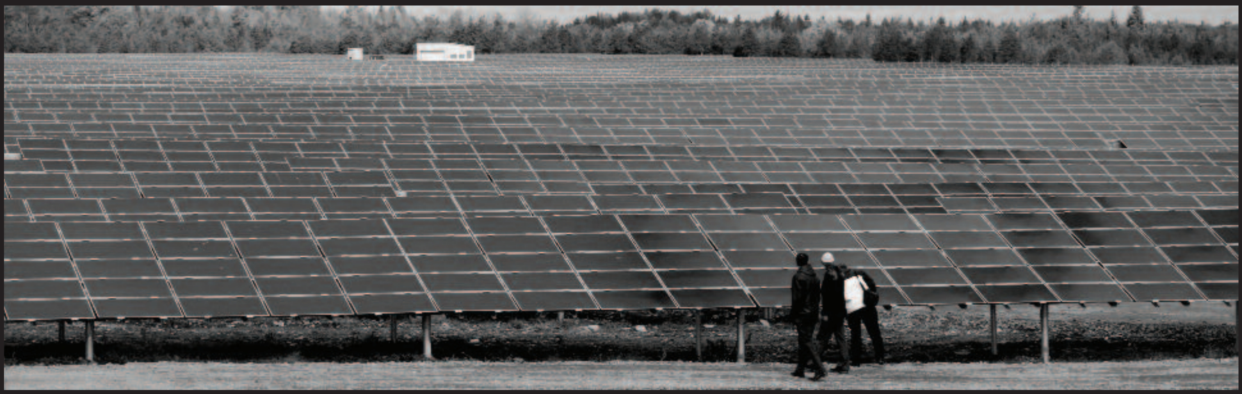


Photo courtesy of Skypower Limited.

Building Ontario's Green Future

Ontario's Green Energy Act lays out a framework to make the province a global leader in clean energy development through the use of renewable energy, distributed energy and conservation, and by creating thousands of jobs. Hydro One's role is to facilitate the connection of a wide variety of energy sources to the grid and ensure that our transmission and distribution system can deliver renewable energy from where it is generated to where it is needed.

Hydro One is currently reviewing core transmission network upgrades across Ontario necessary to support clean energy.

1 MILLION

Smart Meters Installed in 2009

Reaching a Smart Goal

In one of the largest smart meter deployments undertaken by any utility in North America, Hydro One surpassed the key milestone of one million smart meters installed, with almost 750,000 meters communicating at a level capable of reliable meter reading. With this critical infrastructure in place our customers can begin converting to time-of-use pricing in 2010/2011.

16 10+ KW

Renewable Generators Integrated into Ontario's Power Grid

Supporting Renewable Energy Generation

Hydro One is crucial to the successful implementation of the Green Energy Act. As more energy from renewable generation sources, such as solar, wind and biomass, becomes available, Hydro One will take the lead in integrating this energy into Ontario's electricity system, safely and cost-effectively. In 2009, 16 renewable generators, each capable of producing more than 10 KW of electricity, were connected to our distribution system.

Ensuring Reliability. Increasing Capacity.

In 2009, Hydro One invested $918 million in transmission capital projects which included a number of network upgrades designed to facilitate access to new sources of renewable generation and to increase our transfer capability from other jurisdictions.

One of these initiatives, the Bruce to Milton Transmission Reinforcement Project, will connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. Hydro One received the Environmental Assessment approval in December 2009, and construction will begin in 2010.

To provide reliable service to our customers, we continually monitor and evaluate our infrastructure. In 2009, the Southwestern Ontario Capacitor Banks Project identified four capacitor banks that – based on age, condition and importance to the system – were approaching their end-of-life. We made replacing this critical equipment a priority, and installed new capacitors which will also expand transmission capacity in southwestern Ontario.

The connection between our Cherrywood Transformer Station and our Claireville Transformer Station was reinforced to improve reliability and to ensure that it could meet growing demand within the Greater Toronto Area (GTA).

$918 MILLION

Invested in Transmisssion Capital Improvements

Green energy. Educational partnerships. Community outreach. Just a few examples of our commitment to good corporate citizenship in action.

Committed to Conservation

Our commitment to continually improve our environmental performance includes helping Hydro One customers manage their electricity usage more efficiently. In 2005, we launched our Conservation and Demand Management program. Since then, more than 1.5 million customers have saved over 450 million kWh of electricity. That's enough to power approximately 38,000 homes for a year, resulting in greenhouse gas emissions savings of more than 300,000 tonnes of CO_2.

Hydro One employees are reducing their impact on the environment by cutting back on paper use, shutting down engines and turning off computers and unnecessary lights. Initiatives launched through our employee-driven Greener Choices program have resulted in a reduction of an estimated 900 tonnes of CO_2 emissions.

Greener Fleet Rates Gold

Hydro One's efforts to improve both the fuel efficiency and environmental management of our fleet of service vehicles earned us the gold rating from Canada's Energy, Environment and Excellence group. The E3 Fleet program recognizes companies and governments that increase their fleet's fuel efficiency, reduce their carbon footprint and demonstrate leadership in fleet management excellence. Our gold rating was based on a reduction of 525 tonnes of CO_2 emissions achieved by minimizing idling, launching a smart tire inflation campaign, purchasing more fuel-efficient vehicles and optimizing fuel performance by collecting and analyzing vehicle-use data.

Improved Service and Convenience

In 2009, we relaunched our customer website, **www.HydroOne.com**. Now it is easier than ever for Hydro One customers to pay their bills online, manage their accounts and find tips on saving electricity. The site's new power outage tracking system uses state-of-the-art mapping technology to provide customers and other system stakeholders with comprehensive, real-time updates on the size and location of outages, the number of customers affected and the estimated time of service restoration.

161 New Graduates Hired by Hydro One Since 2008

New Skills. New Opportunities.

To be sure we have the people we need to fulfill our mandate of delivering safe, reliable and affordable electricity, Hydro One has taken the lead in establishing partnerships with colleges, universities and First Nations and Métis people. Since 2008, we have hired 161 young professionals into our new graduate program and brought on 393 apprentices.

In February 2009, Colleges Ontario recognized Hydro One with an award for our efforts in advancing college education in the province. Hydro One has invested more than $3 million to partner with Ontario colleges to train and recruit people as engineering technicians and technologists as well as other trades positions in the electricity sector.

Partners in Powerful Communities

Hydro One believes in helping to build strong, healthy communities. Our PowerPlay program provides grants of up to $25,000 to support capital projects for community centres, indoor or outdoor ice rinks, playgrounds, splash pads and sports fields – places where members of the communities we serve can get together and children can engage in sports and active play. In 2009, Hydro One gave a total of $1 million for PowerPlay grants to 108 community projects.

108 PowerPlay Grants to 108 Community Projects in 2009

Visit www.HydroOne.com to read more about what Hydro One is doing for the environment and our customers in the Social Responsibility Highlights brochure.

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
Senior Vice-President, Corporate and Regulatory Affairs

John Macnamara
Vice-President, Health, Safety and Environment

Carmine Marcello
Senior Vice-President, Asset Management

Nairn McQueen
Senior Vice-President, Engineering and Construction Services

Geoff Ogram
Senior Vice-President and Special Advisor

Wayne Smith
Senior Vice-President, Grid Operations

Sandy Struthers
Senior Vice-President and Chief Financial Officer

Ali Suleman
Vice-President and Treasurer

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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 and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP

Concept and Design: THE WORKS www.worksdesign.com

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit www.HydroOne.com.

ANNUAL REPORT 2009

Investing in Ontario's Energy Future

hydroOne

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 21 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. This business represents less than 1% of our total assets.

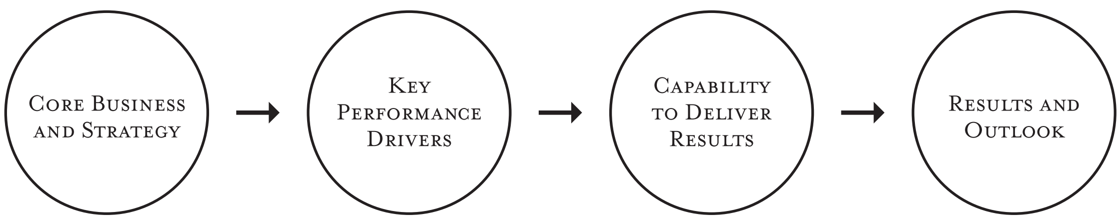
Management's Discussion and Analysis

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, 2009 and 2008.

Executive Summary

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). Our mandate is to provide safe, reliable and cost-effective transmission and distribution of electricity to Ontario electricity users. We operate as a commercial enterprise with an independent Board of Directors. Our strategy is driven by our values: safety, stewardship, excellence and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial and transparent and values our customers. We strive for excellence by being trained, prepared and equipped to deliver high quality service. We value innovation because it allows us to increase our productivity and to develop enhanced methods to meet the needs of our customers. In 2009, 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 while preparing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following governance structure:



Core Business and Strategy

Our corporate strategy is based on our mandate, vision and values. Our vision is to be the leading electricity delivery company in North America. Our strategic goals, which are discussed on page 3, encompass the core values that drive our business. Our strategy touches every part of our core business: safety, our customers, innovation, the reliability and efficiency of our systems, the environment, our workforce, shareholder value, and productivity.

Key Performance Drivers

We have identified performance drivers critical to achieving our strategic goals. Each driver is specific to measuring our success of a specific goal. We establish specific performance targets against each driver every year aimed at achieving our strategic goals over time. For example, we calculate lost-time injury frequency to measure our progress toward an injury-free workplace and use customer surveys to measure the success of our initiatives to increase customer satisfaction. Reduced carbon emissions and the results of our energy efficiency audit are indicative of our commitment to protecting the environment. These and other key performance drivers are included in our discussions of our performance measures beginning on page 4.

Capability to Deliver Results

We continued to use a balanced scorecard approach and set 13 stretch targets for 2009. We continue to strive to manage our key performance drivers and deliver results each and every year. This year we met or exceeded 8 of 13 targets. In delivering results, we remain conscious of our environmental footprint. We exceeded our target for greenhouse gas reductions by 125 metric tonnes, or approximately 31%, and exceeded our target for distribution customer interruptions by 0.4 hours, which is an improvement from last year of 1.2 hours, or nearly 15%. The results of our efforts are fully discussed in the section Performance Measures and Targets beginning on page 4. Our capability to deliver results in each of our strategic areas is limited by risks inherent in the regulatory environment, our business, our workforce and the economic environment. These risks, as well as our strategies to mitigate them, are discussed on page 22.

Results and Outlook

During 2009, our financial fundamentals remained strong, with current year net income of $470 million. Our OEB-approved revenue requirement for our Transmission Business for 2009 was $1,180 million. For our Distribution Business, rates were approved on the basis of the OEB's third generation incentive regulation mechanism (IRM). The approved rates support our work programs necessary to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable or cleaner generation. We maintained "A" category credit ratings and successfully issued $1,150 million in debt financing. A full discussion of our results of operations and financing activities can be found beginning on pages 11 and 15, respectively.

Our estimated future capital expenditures have increased from those disclosed in the 2008 Annual Report primarily as a result of additional investments in the electricity system required to accommodate the anticipated increase in renewable energy generation associated with the Feed-in-Tariff (FIT) Program and investments in advanced technologies to increase functionality and reliability of the electricity grid under the GEA. On September 21, 2009, the Minister of Energy and Infrastructure asked our company to proceed with the planning, development and implementation of specific transmission projects, to develop and implement smart grid infrastructure, and to proceed with upgrades to enable distributed system connected generation. We agreed with this request and we are proceeding with an implementation plan. Our future capital expenditures are more fully discussed beginning on page 17.

Overview

Transmission

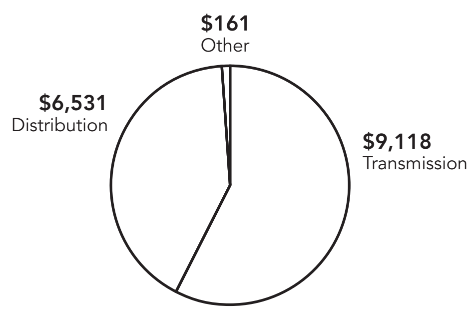
Substantially all of Ontario's electricity transmission system is owned and operated by our Company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centers. In 2009, we earned total transmission revenues of $1,147 million primarily by transmitting approximately 139 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 4,600 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 58% of our total assets.

Distribution

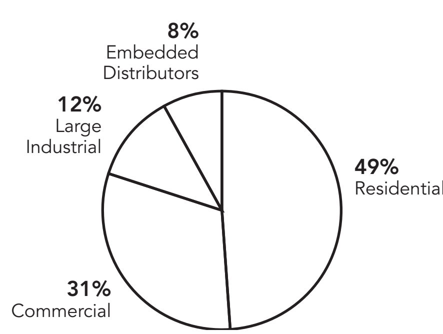
Our distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.3 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 44 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. We earned total distribution revenues in 2009 of $3,534 million. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

Total Assets

December 31, 2009 (Canadian dollars in millions)



2009 Distribution Revenues



Other

Our other business segment contributed revenues of $63 million in 2009 and has assets of about $161 million, which constitute 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. Hydro One Telecom recently constructed a dedicated optical network providing secure, high capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mandate, vision and values. Our mandate is to provide safe, reliable and cost-effective transmission of electricity to Ontario electricity users. Our vision is to be the leading electricity delivery company in North America. Our values include safety, stewardship, excellence and innovation. We are committed to providing innovation and leadership in renewing Ontario's power grid. To that end, we have identified eight strategic objectives:

Creating an injury-free workplace and maintaining public safety: We continue to focus on creating a passion for preventing workplace injuries and ensuring public safety.

Satisfying our customers: In order to satisfy our customers, we focus on reliability and power quality, communicating effectively with our customers, delivering on our commitments, partnering with the communities we serve, providing value for money and building our reputation as a trusted steward of provincial transmission and distribution assets.

Continuous innovation: We are committed to identifying and providing innovative solutions that improve the reliability and efficiency of electricity delivery and allow our customers more capability to manage their power costs.

Building and maintaining reliable, cost-effective power delivery systems: Our transmission strategy is to provide a robust and reliable provincial grid that can accommodate the Province's emerging generation profile and demand requirements. Our distribution strategy entails providing greater visibility, increased control and improved customer service through advanced grid technologies, while continuing to provide reliable service over a wide range of geography and climate.

Protecting and sustaining the environment: We play a central role in reducing Ontario's carbon footprint, both through the delivery of clean and renewable energy and through measures that allow our consumers to manage and reduce their energy usage. We are also focusing on our work methods and equipment, including fleet management and the transition of diesel generation in remote communities to biodiesel generation.

Skill development and knowledge retention: We are addressing our demographic challenges through a comprehensive program of recruitment, training in core competencies, staff development and knowledge transfer.

Maintenance of a commercial culture that increases value for our shareholder: We are committed to operating on a financially sustainable basis and to maintaining or increasing the value of our assets.

Productivity improvement and cost-effectiveness: To achieve our vision as the leading electricity delivery company in North America, we constantly strive to be the most productive through efficiency improvements and effective management of costs. Our goal is to be top quartile in key unit cost metrics relative to our North American electricity industry peer group.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of Ontario's economy and its residents.

Performance Measures and Targets

We measure and target our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we achieve our strategic objectives. In 2009, we met or exceeded 8 of 13 stretch targets. Overall, we are moving towards our strategic goals.

Creating an Injury-Free Workplace and Maintaining Public Safety

The potentially hazardous nature of our business requires a continuous focus on safety. Our people underpin everything we do, and as a result, safety is paramount. Our efforts to achieve an injury-free workplace are measured by our lost-time injury frequency. Overall, we met our challenging 2009 target of 0.3 lost-time injuries per 200,000 hours worked and achieved first quartile performance based on industry benchmarks. We monitor this measure to identify possible situations that may increase the risk of injury. These injuries range from strains to electrical contacts. We continuously emphasize the improvement of safety performance and strive to achieve zero lost-time injuries by ensuring that all staff are appropriately trained and equipped for the hazards that they may face. This involves continued coaching and mentoring, and building on our learning and experience. At the end of 2009, we launched Journey to Zero, a new program aimed at identifying key opportunities for improvement in our health and safety system. We continuously focus on maintaining public safety. In 2008, we began enhancing the security of our transmission stations in the Greater Toronto Area (GTA).

Satisfying Our Customers

Customer satisfaction is also vital to our success. This is measured through aggregate results of independent surveys conducted for each of our customer segments. Our Large Transmission Customer Satisfaction Survey results remained above target with an overall satisfaction level of 91%, reflecting our strong commitment to customer service. In addition, our Large Distribution Customer Satisfaction Survey results improved from 82% to 85% satisfied, as compared to 2008. We continue to be conscious of the needs of our residential and small business customers. Survey results showed an overall satisfaction level of 84%, which is slightly lower than target and last year's level; however, it surpassed the results of 2007 and 2006. We experienced lower results for generator customer satisfaction compared to 2008 for transmission connected and distribution connected generators. Addressing the concerns identified will be an area of focus for 2010. While our overall survey results for customer satisfaction fell short of our 2009 target, we continue to strive for customer service excellence. We continue to make our customers a high priority, and implement targeted strategies designed to meet the unique needs of each customer segment and address their concerns through a range of initiatives to improve customer satisfaction levels.

Continuous Innovation

We are committed to identifying and providing innovative solutions that will improve the reliability and efficiency of electricity delivery and allow our customers more capability to manage their power consumption. Among our continuous innovation initiatives, the installation of smart meters is a priority. We have installed 1,217,000 meters to date, of which 747,000 meters are communicating at a level capable of reliable meter reading. This is one of the largest smart meter deployments by a utility in North America. We fell short of our target of 800,000 meters enabled for meter reading due to the development of new technologies better suited for our rural environment, which will reduce the number of required repeaters and result in lower cost.

Building and Maintaining Reliable, Cost-Effective Power Delivery Systems

As stewards of the province's electricity grid, we aim to retain and build trust in our operations. In 2009, 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. In addition, our aim is to meet the growing demand for renewable generation. The reliability of our transmission and distribution systems is measured by the duration of unplanned customer interruptions throughout the year and our transmission system is further measured by the frequency of unplanned customer interruptions. In 2009, our distribution system performed better than planned, exceeding our target duration of 7.4 hours for customer interruptions with an actual duration of 7.0 hours. This performance is significantly improved from 8.2 hours in 2008.

Due to a number of challenges experienced throughout the year, the reliability of our transmission system was impacted in terms of both frequency and duration of interruptions. On August 20, 2009, tornados caused numerous momentary outages in Southern Ontario which were reflected in our 2009 transmission year-end frequency of unplanned customer interruptions; however, our results remained in the top quartile of performance based on the Canadian Electricity Association results for comparable systems in Canada. The event also affected our year-end transmission duration of unplanned customer interruptions which was 19.7 minutes; higher than the target of 12.4 minutes. This measure was further impacted by an interruption in January as a result of a low-probability high-impact failure at one of our transmission stations. Excluding these specific impacts, the duration measure came close to target. We are conscious that residential customers and businesses of all sizes require reliable service and consequently, we will continue to strive toward improving the reliability of both our transmission and distribution systems.

Protecting and Sustaining the Environment

As stewards of significant electricity assets, we have implemented a number of environmental initiatives aimed at instilling environmental awareness and action within our corporate culture. In 2009, we measured two key metrics related to oil spills and greenhouse gas reductions. We recovered approximately 97% of oil spills from oil-filled electrical equipment, exceeding our target of 90%. We have taken steps to ensure that our oil spill occurrences and response performance continue to improve. These include employee response training, the completion of environmental self-assessments, and the enhancement of our spill-containment systems at our transmission and distribution stations.

We take our responsibility to reduce our carbon footprint very seriously. In 2009, we removed approximately 525 metric tonnes of greenhouse gases from the environment, significantly exceeding our target of 400 metric tonnes. This achievement was due to a number of initiatives aimed at the efficiency of fleet utilization, including our Tire Smart Program and the purchase of fuel-efficient and hybrid vehicles. The environmental management of our fleet of service vehicles earned our company a gold rating from Canada's Energy, Environment and Excellence group. Our continued commitment to the people of Ontario has been recognized again this year by *Corporate Knights*, an independent company focused on promoting and reinforcing sustainable development in Canada. We were named the top Corporate Citizen in Canada, an improvement from our 6th place ranking in 2008. The ranking recognized us as having successfully managed our specific environmental, social and governance performance and having implemented a comprehensive Conservation and Demand Management (CDM) program.

Skill Development and Knowledge Retention

Given the retirement profile of our employees, we are entering 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. We have embarked on an aggressive workforce renewal program. In addition to our partnership with four community colleges, we strengthened our association with various Canadian universities as part of a comprehensive strategy to meet our staffing needs well into the future. Our goal to attract and retain future sector leaders involves demonstrating Hydro One as an employer of choice. In addition, we aim to facilitate retention and mentoring by focusing on employee engagement. We measure employee engagement across all lines of business using a confidential employee engagement survey. The grand mean score in 2009 was 3.63 out of 5, an improvement from the 2008 score of 3.51, but slightly lower than the 2009 target of 3.68. Detailed results of the 2009 survey will be used to actively address lower performing areas and effectively implement targeted strategies designed to increase engagement levels.

Maintenance of a Commercial Culture That Increases Value for Our Shareholder

In 2009, we continued our commitment to maintain strong financial fundamentals. Our targets included net income and our credit ratings, which were both achieved. A discussion of our financial results can be found on page 11 and our liquidity and capital resources on page 14. Our financial performance and the business environment in which we operate are taken into consideration in the setting of both our short-term and long-term credit ratings. During 2009, our long-term and short-term debt credit ratings remained unchanged. Credit ratings are provided by DBRS Limited, Moody's Investors Service Inc. and Standard & Poor's Rating Services Inc. (S&P). Maintaining credit ratings in the "A" category allows us to continue to access the long-term debt markets. We have been able to successfully secure sufficient and cost-effective debt financing even under extremely challenging market conditions. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

Productivity Improvement and Cost-Effectiveness
In 2009, we remained focused on workplace productivity and its contribution as an enabler of our work programs. For our Transmission Business, productivity is measured using the cost per asset value which is calculated as the capital and maintenance program expenditures as a percentage of transmission assets. For our Distribution Business, the calculation is normalized for line length due to the rural nature of our service territory. The targets for both measures were to achieve top-quartile when benchmarked against comparable North American utilities. Transmission productivity for the year was slightly better than target, and distribution productivity was essentially on target.

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 temporarily 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 and 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 in August 2007. On September 17, 2008, the Province directed the OPA to review a portion of its proposed IPSP focusing on renewable energy and conservation as well as to undertake an enhanced process of consultation with First Nations and Métis communities. As a result of this directive and the enactment of the GEA, we are uncertain as to when the OPA will file a revised IPSP.

The GEA provides the framework for renewable energy projects and increased conservation. A number of regulations and programs, needed to fully implement the legislation, were introduced in the latter part of 2009.

An amendment to the deemed licence conditions of the *Ontario Energy Board Act, 1998*, as set out in the GEA, requires that distributors provide priority connection access for qualified renewable energy generation facilities and prepare plans for approval by the OEB that identify expansion or reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities.

The OPA continues to procure new, cleaner and renewable generation in Ontario. On September 24, 2009, the OPA announced the FIT Program in accordance with the directive issued by the Minister of Energy and Infrastructure to the OPA. The program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW. As a result of the September 21, 2009 letter from the Minister of Energy and Infrastructure, our company is working proactively with the appropriate organizations within our industry to develop strategies and processes to address generation requirements and assess the impact on our network.

In 2009, the OEB undertook a review of its codes, rules and guidelines in support of the GEA. On October 20, 2009, the OEB finalized amendments to the Transmission System Code (TSC), and adopted a "hybrid" approach to cost responsibility between transmitters and generators for "enabler facilities." Enabler facilities are lines or stations to connect two or more renewable generation facilities to the transmission grid. The hybrid option would see the initial pooling of the costs of enabler lines by the transmitter, with generators paying their pro-rata share, based on generator capacity, when ready to connect. To be eligible for this cost treatment, enabler facilities must meet certain detailed requirements established in the TSC.

The amendments to the Distribution System Code (DSC), finalized on October 21, 2009, revised the OEB's approach to assigning cost responsibility between a distributor and a generator for the connection of renewable energy generation facilities. The OEB defined three types of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. For generators that are connecting directly to a distributor's system, connection asset costs will continue to be borne by generators, while distributors will be required to fund all expansion costs identified in a plan, other generator-requested expansion costs up to a cap of $90,000/MW per project (the generator paying the rest), and all renewable enabling improvements.

In 2009, the OPA continued to be responsible for coordinating the delivery and funding of CDM programs. This coordination furthered initiatives undertaken by individual LDCs, including the Distribution Businesses of our subsidiaries Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements associated with the third phase Market Adjusted Rate of Return (MARR). Our CDM programs funded through the OPA in 2009 amounted to approximately $16 million compared to $8 million in 2008. In 2008, we completed our OEB program requirements associated with the third phase of MARR which amounted to approximately $43 million. The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps as specified to establish CDM targets to be met by LDCs and other licensees. The directive may require the OEB to specify, as a condition of a licence, the conservation targets to be met by LDCs and other licensees. To date, no such directive has been issued to the OEB and we have not been provided specific targets.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. These meters are expected to 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 interim smart meter entity that will oversee the collection and management of data. LDCs, including our Distribution Businesses, are accountable for the deployment 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. We are advancing solidly toward our goal of having smart meters installed in every home and business by December 31, 2010. In 2009, we were also able to complete the majority of interface testing, including rural application. In 2010, we will continue to focus on building an advanced distribution solution that will leverage our smart meter investment required to connect and manage large volumes of distributed generation on our distribution system (see Future Capital Expenditures).

Transmission Rates

Hydro One Networks

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

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 (ROE) 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 Revenue Difference Deferral Account (RDDA), Earnings Sharing Mechanism (ESM), export and wheeling fees liabilities and the transmission market ready regulatory asset. The disposition of the RDDA and ESM was factored into rates and 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 are 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 UTRs for implementation on November 1, 2007, through to December 31, 2008. The new rates reflected the approved changes to our revenue requirement and charge determinants and were, on average, 12% lower than previously approved rates primarily due to a reduction in the ROE. The new rates resulted in an approximate 1% decrease in the average customer's total electricity bill.

On May 30, 2008, we submitted an application to the OEB to adjust UTRs for our Transmission Business, effective January 1, 2009. On August 28, 2008, the OEB approved our application reflecting the 2008 OEB-approved revenue requirement given the full repayment to customers of the ESM and RDDA as at December 31, 2008. This resulted in an average increase of approximately 9% in our revenue requirement allocation from UTRs and an approximate 1% increase on an average customer's total bill.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirements of approximately $1,233 million and $1,341 million based on a ROE of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision, effective July 1, 2009, which resulted in a reduced revenue requirement of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved ROE of 8.01% and 8.16%. The decision also required the establishment of new variance accounts to track the difference between the forecasted and actual external revenues for export services, secondary land use and net maintenance services primarily provided to generators. The OEB decision disallowed development capital expenditures of $180 million in 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, we filed supplemental evidence regarding two of the development capital projects amounting to approximately $160 million. On December 16, 2009, the OEB approved our supplemental submission increasing the approved 2010 revenue requirement to $1,257 million on the basis of an updated 2010 ROE of 8.39%. These decisions resulted in an increase in transmission tariff rates of approximately 2% and 9% for 2009 and 2010, respectively, representing a less than 1% increase on an average customer's total bill in each year.

On December 11, 2009, the OEB issued its final report on the cost of capital review which was initiated to determine whether current economic and financial market conditions warranted an adjustment to any of the cost of capital parameters values used by the OEB to set utility ROE. In its report, the OEB decided to continue to use a formula-based equity risk premium approach; however, the OEB determined that the current formula-based ROE needed to be reset and refined.

As a result of the OEB's cost of capital report, on January 5, 2010, we filed a motion with the OEB to review aspects of its decision on our 2010 transmission rates. Specifically, we requested that the ROE and short-term debt rate used in calculating the 2010 revenue requirement be increased to 9.75% and 1.93%, respectively, to reflect the application of the approved rates under the new OEB-approved formula. The oral hearing is scheduled for March 26, 2010.

We are currently preparing evidence to support a transmission rate application for 2011 and 2012. The application is anticipated to be filed with the OEB in the first quarter of 2010. This application will continue to support aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application will be filed using the new OEB-approved formula for ROE and is anticipated to take into consideration the OEB staff report on the regulatory treatment of infrastructure investment in connection with rate-regulated activities of Ontario distributors and transmitters, issued in January 2009. The report allows utilities to include prudently incurred construction work in progress in rate base, among other things.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO who facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and the IESO itself.

In 2006, the OEB initiated a process to establish an IRM for the years 2007 to 2010. The process included a formulaic approach to establishing 2007 rates with a rate re-basing approach to be staggered across all Ontario distributors between 2008 and 2010.

Hydro One Networks

In accordance with the OEB's multi-year distribution rate-setting plan, our subsidiary Hydro One Networks, submitted the revenue requirement portion of its 2008 cost of service application on August 15, 2007. The application sought the approval of a revenue requirement of $1,067 million based on a ROE of 8.64%. We requested a distribution rate increase amounting to a net average increase of less than 1% on the average customer's total bill. The application included 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.

On December 18, 2008, the OEB issued a decision approving substantially all of our work program expenditures, effective May 1, 2008, with an implementation date of February 1, 2009. The decision approved the establishment of the Revenue Recovery Account (RRA or Rider 4) to record the revenue differential between existing distribution rates and new rates from May 1, 2008. The RRA is being recovered over a 27-month period, commencing February 1, 2009, and ending April 30, 2011. As part of the decision, the OEB also approved certain excess functionality expenditures for smart meters and the continuance of the $0.93 cents per month per metered customer. In a past proceeding, the OEB approved our expenditures incurred related to minimum functionality for advanced metering infrastructure for recovery. As a result, the difference between revenue recorded on this basis and actual recoveries received under existing rate adders are reflected as the carrying value of the regulatory asset account.

In late 2008, we filed an incentive regulation application for 2009 rates, which was updated in January 2009, to reflect the impact of the 2008 distribution rate decision. The application was filed on the basis of the OEB's third generation IRM process which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision approving the basic IRM increase and a change of $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009, and resulted in an increase of less than 1.5% on an average customer's total bill.

In 2009, we filed a cost of service application with the OEB for 2010 and 2011 distribution rates reflecting our plan to invest in our network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. The application seeks OEB approval of revenue requirements of approximately $1,150 million and $1,264 million based on a ROE of 8.11% and 9.09% for 2010 and 2011, respectively. The resulting distribution tariff rate increase is approximately 10% and 13% in 2010 and 2011, respectively, or approximately 3% and 4% on an average customer's total bill. The oral hearing began on December 7, 2009.

As a result of the OEB's cost of capital report issued in December 2009, we subsequently updated our revenue requirement. The revised revenue requirements of $1,196 million in 2010 and $1,295 million in 2011 reflect the application of the ROE of 9.75% under the cost of capital formula.

Our application included the Green Energy Plan for our Distribution Business, filed in response to the GEA which directed the OEB to require transmitters and distributors to file plans that would lead to the expansion of their systems to facilitate renewable energy. Our plan identifies the expansion and reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities and plans for the development and implementation of the smart grid in relation to our distribution system.

We filed an update to our pre-filed evidence on September 25, 2009, to reflect changes to the *Ontario Energy Board Act, 1998*, as amended by the GEA and stipulated in Ontario Regulation 330/09. The amendments provided a new mechanism for rate protection whereby some or all of the OEB-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of renewable energy generation to its distribution system may be recovered from all provincial ratepayers rather than solely from ratepayers of the distributor making the investment. In the last quarter of 2009, the OEB initiated a proceeding to address the extent to which the cost of distribution system investments made to enable the connection of renewable generation can be recovered from all of the province's ratepayers in accordance with Ontario Regulation 330/09. The OEB has expressed its preference to delay our oral hearing until the OEB issues its final report. We anticipate the oral hearing to resume in the first quarter of 2010.

Hydro One Brampton

On November 1, 2007, our subsidiary Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's second generation IRM policy that incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 19, 2008, the OEB released its decision and revised rates, including an amount of $0.67 cents per month per metered customer for smart meters, and were approved with an implementation date of May 1, 2008. The overall impact on an average customer's total bill was a reduction of approximately 3%.

On November 7, 2008, an application was filed on the same basis for 2009 distribution rates. On March 13, 2009, the OEB released its decision and approved the submission on the basis of its second generation IRM policy. The revised rates, including an amount of $1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009. Overall, the impact on an average customer's total bill was marginal.

On November 6, 2009, an application for 2010 distribution rates was filed on the basis of the OEB's second generation IRM process, for which the overall impact on an average customer's total bill would be marginal. Their distribution rates will be put forth for a cost of service re-basing in 2011.

Hydro One Remote Communities Inc.

On August 29, 2008, we filed a 2009 cost of service rate application proposing an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all work program expenditures and the proposed rate increase of 4.4% effective May 1, 2009, resulting in a 4.4% increase to an average residential customer's total bill.

On November 4, 2009, we filed an application for 2010 rates under the OEB's third generation IRM, seeking approval of an increase of approximately 2% to basic rates for the distribution and generation of electricity effective May 1, 2010, which would increase an average customer's total bill by 2%. The increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications.

Results of Operations

Revenues

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	$ Change	% Change
Transmission	**1,147**	1,212	(65)	(5)
Distribution	**3,534**	3,334	200	6
Other	**63**	51	12	24
	4,744	4,597	147	3
Average annual Ontario 60-minute peak demand *(MW)*[1]	**20,798**	21,820	(1,022)	(5)
Distribution – units distributed to customers *(TWh)*[1]	**28.9**	29.9	(1.0)	(3)

[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. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenue associated with transmitting excess generation to surrounding markets and ancillary revenues, which are primarily attributable to maintenance services primarily provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were lower by $65 million, or 5%, compared to 2008, mainly due to lower average monthly peak demands experienced during the year. The average annual Ontario 60-minute peak demand and the overall related load were 1,022 MW and 12,262 MW lower than last year, respectively, resulting in lower revenues of $36 million.

Export service revenue attributable to the transmission of electricity to other jurisdictions was lower by $14 million as a result of lower volume and the impact of the May 28, 2009 OEB decision. This decision also resulted in lower ancillary revenues of $9 million. The OEB decision requires export services and net ancillary revenues in excess of forecast levels to be recorded as regulatory liabilities for disposition to ratepayers.

Transmission revenues for the year were also affected by two other OEB-approved transmission tariff rate increases that occurred during the year. These increases were offset by adjustments to our earned revenues reflecting the refund of the amounts previously recorded as revenue reductions in prior years which resulted in a net decrease of $6 million during the year.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. 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 $200 million, or 6%, compared to 2008 including an increase in the recovery of higher purchased power costs of $145 million, as described below under Purchased Power.

After deliberation of our written and oral evidence, the OEB approved increases related to our smart meter program and our distribution tariff for our subsidiary Hydro One Networks. The decisions were issued on December 18, 2008, in respect of our cost of service application, and on May 13, 2009, in respect of our rate application under the IRM. As a result, our distribution revenues increased by $64 million compared to last year. These tariff rate increases, which support the maintenance and investment requirements of our distribution system that enable the safe and reliable delivery of electricity to our customers throughout Ontario, were implemented on February 1, 2009, and June 1, 2009, respectively.

Distribution revenue increases were partially offset by lower energy consumption, resulting primarily from the milder weather and the economic downturn, which reduced our distribution revenues by $11 million compared to last year. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective March 31, 2008, resulting in a reduction of $5 million for the year.

We also experienced higher other revenues of $7 million primarily due to the recognition of certain OEB-approved deferral accounts and increased OPA incentive revenues from the implementation of OPA-funded CDM programs during the year.

Other
Higher revenues derived from a newly constructed dedicated optical network, which provides secure, high capacity connectivity across numerous health care locations in Ontario, contributed to an increase in revenues in our Telecom Business of $12 million, or 24%, compared to 2008.

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 wholesale market service charges and transmission charges levied by the IESO. The commodity cost of energy for low-volume and other designated customers are based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. 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 impacting the reporting period 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, 2007	1,000	750	5.0	5.9
May 1, 2008	600	750	5.0	5.9
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7

Purchased power costs increased in 2009 by $145 million, or 7%, to $2,326 million for the year compared to 2008. The increase in our purchased power costs was primarily due to the impact of changes in the OEB's RPP rate for residential and other eligible customers of $122 million, the impact of higher charges levied by the IESO of $33 million which includes increased wholesale market service charges, and an increase in purchased power costs for customers who are not eligible for the RPP of $31 million. These increases were partially offset by a reduction of $41 million as a result of lower demand for electricity.

Operation, Maintenance and Administration
Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are 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)	**2009**	2008	$ Change	% Change
Transmission	**438**	387	51	13
Distribution	**564**	531	33	6
Other	**55**	47	8	17
	1,057	965	92	10

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $51 million, or 13%, in 2009 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were higher by $28 million compared to the prior year. These increases were primarily attributable to expenditures on our planned station maintenance programs to address aging infrastructure, particularly on transformers and other power equipment and higher requirements for unplanned corrective maintenance. Our work program also included expanded forestry programs to improve system reliability and increased engineering support. Our expenditures in support of the transmission system have also increased by $23 million primarily reflecting the impact of lower expenditures in the prior year related to a one-time settlement credit associated with the transfer of assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services Commission of Ontario (FSCO). Increased expenditures in support of the transmission system are also due to higher information technology application support and enhancements substantially offset by the reallocation of resources in support of our larger capital work program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $33 million, or 6%, compared to last year. Our work program expenditures increased by $18 million primarily resulting from higher expenditures on our customer care programs, expanded forestry programs to improve system reliability, unplanned line maintenance and corrective planned station maintenance. Our expenditures in support of our Distribution Business were higher by $15 million primarily reflecting the impact of lower expenditures in the prior year related to the one-time settlement credit associated with the transfer of assets to the Inergi pension plan. Increased expenditures in support of the distribution system are also due to higher information technology application support and enhancements partially offset by the reallocation of resources in support of our larger capital work program.

Depreciation and Amortization

Depreciation and amortization expense decreased by $11 million, or 2%, to $537 million this year. This decrease was attributable to reduced amortization primarily related to the full recovery of a regulatory asset in the prior year. The lower amortization was partially offset by increased depreciation expense mainly attributable to new assets coming in service, consistent with our ongoing capital work program.

Financing Charges

Financing charges increased by $16 million, or 5%, to $308 million for 2009 compared to last year. The increase was primarily due to higher net interest expense reflecting higher average levels of debt, lower investment income reflecting lower average investments and lower average short-term interest rates and a $6 million interest credit in the prior year related to the Inergi pension asset transfer settlement. The increase was partially offset by lower average long-term borrowing rates and higher interest capitalization due to increased construction associated with our ongoing capital work program.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the 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, the liability method is used. The change in future taxes relating to the unregulated businesses and to the regulated businesses, in respect of temporary differences that are not considered for the rate-making process, result in a future tax provision that is charged to the income statement. The change in future taxes relating to temporary differences of the regulated business that are considered for the rate-making process results in a regulatory asset.

The provision for payments in lieu of corporate income taxes decreased by $67 million, or 59%, to $46 million compared to 2008. The year-over-year decrease results from a reduction in the statutory rate from 33.5% to 33.0% combined with the impact of increased temporary differences primarily relating to higher capital cost allowance being claimed on our information system and smart meter investments in excess of depreciation. These impacts were partially offset by an increase to the provision for future taxes.

Net Income

Net income of $470 million was lower by $28 million, or 6%, compared to 2008 results. Net income was affected by higher operation, maintenance and administration expenditures primarily related to planned work programs necessary to sustain our transmission and distribution systems and the impact of a one-time settlement credit in the prior year associated with the transfer of assets to the Inergi pension plan. Lower transmission revenues resulted from lower average monthly peak demands and lower export service revenues. These impacts were partially offset by a higher OEB-approved distribution tariff in support of necessary work programs that enable the safe and reliable delivery of electricity. In addition, payments in lieu of corporate income taxes were lower, reflecting higher capital cost allowance deductions.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2008 through December 31, 2009. 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)				**2009**				2008
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31[2]	Sep. 30	Jun. 30	Mar. 31
Total revenues[1]	**1,207**	**1,144**	**1,090**	**1,303**	1,194	1,126	1,055	1,222
Net income[1]	**111**	**100**	**82**	**177**	131	112	98	157
Net income to common shareholder[1]	**106**	**96**	**77**	**173**	126	108	93	153

[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 December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008.

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 resources 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)	**2009**	2008
Operating activities	**892**	1,052
Financing activities		
Long-term debt issued	**1,150**	1,050
Long-term debt retired	**(400)**	(540)
Short-term notes payable	**55**	–
Dividends paid	**(188)**	(259)
Investing activities		
Capital expenditures	**(1,566)**	(1,284)
Other financing and investing activities	**15**	9
Net change in cash and cash equivalents	**(42)**	28

Operating Activities

Net cash from operating activities decreased by $160 million compared to last year, to $892 million. This reduction primarily resulted from higher accounts receivable balances reflecting increased commodity costs and collection cycles associated with the economy, combined with changes in accounts payable related to power purchases. There is a lag in timing between IESO invoices for power purchases and the collection of outstanding accounts receivable balances. In addition, our cash from operating activities was impacted by the net change in our transmission and distribution regulatory accounts, which included the 2008 repayment to our customers of amounts recorded in the transmission RDDA.

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 $1,000 million in short-term notes with a term to maturity of less than 365 days. At December 31, 2009, we had $55 million of short-term notes outstanding. The Commercial Paper Program is supported by committed revolving credit facilities with a syndicate of banks of $1,000 million as at December 31, 2009 maturing August 20, 2010. On February 2, 2010, the Company entered into an additional $500 million credit facility maturing in February 2013. On February 3, 2010, the Company reduced the $1,000 million credit facility maturing on August 20, 2010, to $750 million. In addition, in January 2010, the Company purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014, as a form of alternate liquidity to supplement its bank credit facilities. 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, 2009, we had $6,875 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August 2011 is $3,000 million, of which $2,750 million was remaining and available as at December 31, 2009.

		Rating
Rating Agency	Short-Term Debt	Long-Term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	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 agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide 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.

We issued $1,150 million in long-term debt under our MTN Program in 2009 including $250 million issued under adverse economic conditions in the fourth quarter. We also repaid $400 million in maturing long-term debt. In comparison, during 2008, we issued $1,050 million in long-term debt under our MTN Program and we repaid $540 million in maturing long-term debt. In 2009, the amount of short-term notes increased by $55 million compared to last year but was unchanged in 2008. We also issued $500 million during the first month of 2010, leaving $2,250 million remaining issuable under the MTN Program as at February 11, 2010.

In 2009, we paid dividends to the Province in the amount of $188 million, consisting of $170 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $241 million and preferred dividends of $18 million. In 2009, cash dividends per common share were $1,700 compared to $2,410 per common share in 2008. Cash dividends per preferred share were $1.375 in each of 2009 and 2008.

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 and maintenance of the deemed regulatory capital structure. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

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)	**2009**	2008	$ Change	% Change
Transmission	**918**	704	214	30
Distribution	**643**	570	73	13
Other	**5**	10	(5)	(50)
	1,566	1,284	282	22

Transmission

Transmission capital expenditures increased by $214 million in 2009 to $918 million, compared to 2008. Expenditures to expand and reinforce our transmission system were $520 million, representing an increase of $218 million over last year. This increase is attributable to a number of significant inter-area network upgrade projects to support the supply mix objectives for generation as well as local area supply projects to address growing loads. We also experienced an increase in expenditures on our load projects, which was offset by a reduction in expenditures on our generation projects compared to the prior year. During 2009, we connected approximately 1,285 MW of new generation to our transmission system, compared to 1,940 MW in 2008.

Inter-area network upgrades with significant expenditures include the Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area; the South Western Ontario Capacitor Banks Project, which provides interim protection to the Bruce Nuclear facility and which will expand transmission capacity in South Western Ontario; the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro Québec interconnection; and the Northeast Transmission Reinforcement Project, which will increase the North-South Interface transfer capability to access available northern generation. The impact of these investments was partially offset by the substantial completion in 2008 of an interconnection project with Québec that will increase access to emission-free hydroelectric power by 1,250 MW.

Local area supply projects with significant expenditures include our GTA West Transmission Reinforcement Project and our Woodstock Area Transmission Reinforcement Project, both of which will increase capacity to ensure supply reliability in those areas, and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, which will increase transmission capacity in the western Brampton area to allow for future load growth. The impact of these increases was partially offset by our Essa Transformer Station to Stayner Transformer Station connection, which was placed in service this year and has improved the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $281 million, representing an increase of $13 million compared to 2008. This increase was primarily due to the refurbishment and replacement of end-of-life equipment associated with various line and station projects and higher component replacement expenditures as a result of both emergency restoration work and planned work programs associated with aging infrastructure. These increases were substantially offset by lower expenditures relating to the completion of our Claireville Transformer Station Project which has improved reliability.

Our other transmission capital expenditures were $117 million in 2009, representing a reduction of $17 million from the prior year. This decrease was mainly attributable to lower project support requirements, lower expenditures associated with theft prevention programs and lower information technology project expenditures related to an entity-wide information system replacement and improvement project to replace end-of-life systems and improve productivity, the second phase of which was placed in service during the year.

Distribution

Distribution capital expenditures increased by $73 million to $643 million in 2009, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $332 million, an increase of $63 million compared to last year. These increases primarily reflect ongoing investments required to meet smart meter targets, consistent with government policy. During the year, we installed approximately 433,000 smart meters, bringing our cumulative program total to about 1,217,000 meters. We are also focused on the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. This is one of the largest smart meter deployments by a utility in North America and will start to see our customers convert to time-of-use pricing in 2010.

Expenditures to sustain our distribution system were $242 million, an increase of $11 million from 2008. This increase was primarily the result of increased planned line work programs including the replacement of end-of-life equipment, increased investment to replace components within our distribution stations and increased engineering and construction work to upgrade or replace wholesale meters. These increases were partially offset by lower unplanned line work resulting from storm damage. Our other distribution capital expenditures were $69 million in 2009, which were relatively unchanged compared to the prior year. We experienced lower information technology project expenditures related to an entity-wide information system to replace end-of-life systems and improve productivity, the second phase of which was placed in service during the year. These were offset by increased other support costs including facilities improvement work.

Other

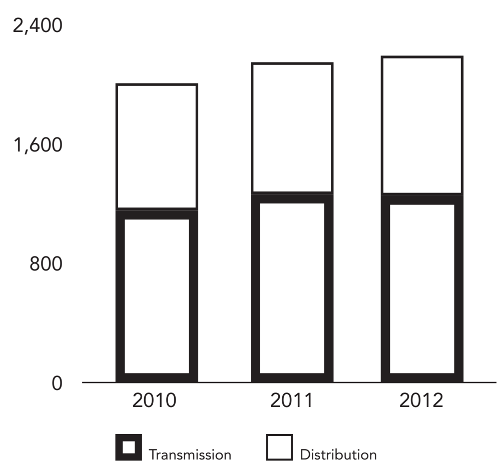
Other capital expenditures declined largely as a result of the substantial completion in 2008 of a dedicated network necessary to deliver on contracts providing secure, high capacity connectivity across numerous health care locations in Ontario.

Future Capital Expenditures

Our capital expenditures in 2010 are budgeted at approximately $2.0 billion. The 2010 capital budgets for our Transmission and Distribution Businesses are about $1,150 million and $850 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to increase to approximately $2.1 billion in 2011 and approximately $2.2 billion in 2012. These expenditures reflect the sustainment requirements of our aging infrastructure budgeted at approximately $530 million in 2010, $620 million in 2011 and $670 million in 2012. Development projects, including inter-area network upgrades that reflect supply mix policies to phase out coal generation and local area supply requirements, are budgeted at approximately $890 million in 2010, $780 million in 2011 and $550 million in 2012. These development investments also reflect the continued mass deployment of smart meters within our Distribution Businesses and the building of the required smart meter infrastructure in support of conservation objectives. We will leverage the smart meter investment to build a smart grid which will enhance our operations and support distributed generation. Other capital expenditures related to operations amount to approximately $410 million in 2010, $290 million in 2011 and $230 million in 2012. Our capital

Future Capital Expenditures

(Canadian dollars in millions)



expenditures to support the requirements under the GEA are approximately $190 million in 2010, $450 million in 2011 and $740 million in 2012. We are proceeding with our investments in support of the GEA to facilitate renewable generation consistent with the FIT Program.

Capital expenditures of our other business segment are budgeted at about $15 million in 2010, primarily reflecting the continued build out of the fibre-optic network.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2010 to 2012, amounting to about $3.7 billion, including 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. The investment plan includes targeted component replacements of air blast circuit breakers, switchgear, autotransformers and wood pole structures to maintain the performance of assets. Also, the reconstruction of transformer stations is planned for the Burlington TS 115 kV Switchyard and Sir Adam Beck Switching Station to ensure future reliability. These sustaining investments are necessary to ensure that we will continue to meet all regulatory, compliance, safety and environment objectives.

Inter-area network projects, required to accommodate new generation related to supply mix policies, include our Bruce to Milton Transmission Reinforcement Project to connect nuclear generation and new wind generation in the Huron-Grey-Bruce area. In December 2009, we received conditional environmental assessment approval for the project, which involves constructing a new 500 kV line. In October 2009, Niagara Escarpment Commission (NEC) approval was obtained but this approval is presently under appeal. The appeal hearing is scheduled to be completed in February 2010. We are also installing station equipment in Southwestern and Northeastern Ontario to increase transmission capacity. Another project to increase transmission capability includes the installation of Static Var Compensators (SVCs) at existing stations in North Eastern Ontario. This equipment will mitigate congestion and enhance the transfer capability between Northern Ontario and Southern Ontario and the transmission system north of Sudbury, enabling new hydroelectric generation.

Other projects included in the transmission investment plan include local area supply transmission reinforcements, such as Southern Georgian Bay, Woodstock and Midtown Toronto, for which we recently filed a leave-to-construct application with the OEB.

We continue to work with our load customers in order to meet their growth requirements. 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 a new transformer station to serve Mississauga and expansions of transformer stations serving Brampton, Kingston, York Region and Mississauga. To address other future needs for local load connections, we are in discussions with customers for major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Mississauga, Oshawa, Woodstock, Essex County Chatham-Kent, Ancaster and Brampton. Targeted investments in customer delivery point performance, power quality and our 115 kV and 230 kV systems are expected to lead to improved reliability.

Our investment plan is also composed of capital expenditures to support the GEA. On September 21, 2009, the Province requested that we proceed with the planning and implementation of 20 major transmission projects across Ontario in support of the GEA and in anticipation of the increase in renewable energy generation associated with the OPA's FIT Program. These investments include bulk transmission investments, enabling lines and various equipment to support the two-directional flow of electricity. Our company is working proactively with the appropriate organizations within our industry to implement these requirements.

The development of distributed generation to be connected to the distribution system will require upgrades at some transformer stations, including the installation of SVCs. Where there is significant distributed generation interest, new dedicated transformer stations may also be required. Also, several major transmission development projects are required, with in-service dates between 2013 and 2020, to provide for new renewable generation. The construction of these projects is scheduled to commence after 2011. In the last quarter of 2009, we initiated the planning for the Northwest Transmission Expansion Project, as well as several other large projects, under Ontario's *Environmental Assessment Act*. The project is needed to incorporate new renewable generation, such as hydroelectric and wind, in the Lake Nipigon area and to provide additional electricity supply capability to meet the needs of existing and future customers in the area north of Lake Nipigon.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon various approvals including OEB leave-to-construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities, as well as the timing and level of generator contributions for enabling facilities under recent amendments to the TSC. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Capital expenditures for the period 2010 to 2012 are estimated to be approximately $2.7 billion, including capital expenditures to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There is a continuation of investments to replace end-of-life equipment and components with a focused increase on wood pole replacements and submarine cables to address deteriorating assets. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

In accordance with government policy, we anticipate having our Smart Meter Project substantially completed in 2010, with some work effort continuing into subsequent years. The deployment of smart meters will further be leveraged to create a smart grid that is capable of providing a communication infrastructure to enable new smart functions and applications across our system that will support the connection of clean and renewable generation. The budget includes investments in smart grid, commencing with standards and technology development for our time-of-use pilot.

Capital expenditures to support the requirements under the GEA include the undertaking of increased generation connection activity and performing upgrades to the distribution system, such as station upgrades for protection and control and the installation of circuit breakers or new feeder positions to accommodate new generation.

The actual timing and expenditures is uncertain as it is dependent upon various approvals, including OEB rate application approvals, as well as the extent to which the cost of distribution system investments made to enable the connection of renewable generation can be recovered from all of the province's ratepayers. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

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, 2009 (Canadian dollars in millions)	Total	2010	2011/2012	2013/2014	After 2014
Contractual obligations *(due by year)*:					
Short-term note payable	55	55	–	–	–
Long-term debt – principal repayments	6,875	600	1,100	850	4,325
Long-term debt – interest payments	5,967	372	669	548	4,378
Inergi outsourcing agreement[1]	222	104	118	–	–
Operating lease commitments	59	9	12	12	26
Environmental obligations[2]	389	24	68	79	218
Total contractual obligations[6]	13,567	1,164	1,967	1,489	8,947
Other commercial commitments *(by year of expiry)*:					
Bank line[3]	1,000	1,000	–	–	–
Letters of credit[4]	112	112	–	–	–
Guarantees[4]	326	326	–	–	–
Pension[5]	10	10	–	–	–
Total other commercial commitments	1,448	1,448	–	–	–

[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. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

[2] The Company records a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The expenditure pattern reflects our planned work program for the period.

[3] As a backstop to our Commercial Paper Program, we have a $1,000 million revolving standby credit facility with a syndicate of banks which matures in August 2010. On February 2, 2010, the Company entered into an additional $500 million facility with a syndicate of banks which matures in February 2013. On February 3, 2010, the Company reduced the $1,000 million facility to $750 million.

[4] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. The other $5 million included in letters of credit pertains to operating letters of credit relating to an agreement to purchase goods and to surety bonds. 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 and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. 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 contributions beyond 2009 are not estimable at this time.

[6] 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 agreements are considered individually material, and the majority do not extend beyond December 31, 2010.

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 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 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. In January 2010, the Company purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014, as a form of alternate liquidity to supplement its bank credit facilities.

Considerations of Current Economic Conditions

Effect of Load on Revenue

The load is expected to decline in 2010 due to the impact of CDM coupled with a below-average growth in the Ontario economy. The economic growth, although moderate, is expected to partially induce load growth in all sectors of the Ontario economy. Overall load growth due to economy alone is forecasted to be approximately 0.4%, with the commercial sector only marginally outperforming residential and industrial sectors. The load impact of CDM and Embedded Generation is expected to have a substantial negative impact on load growth of approximately 4%. On the whole, load is expected to decline by about 3.7%. A reduction in load will negatively affect our revenues.

Effect of Interest Rates

Changes in interest rates will impact the calculation of our revenue requirements filed with the OEB. The first component impacted by interest rates is the return on equity. The OEB-approved adjustment formula for calculating return on equity will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A" rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield or the "A" rated Canadian utility spread used in the current OEB formula for determining our rate of return on equity would reduce our Transmission Business' results of operations by approximately $15 million and our Distribution Business' results of operations by approximately $10 million. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work program requirements, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, blanket orders, vendor alliances and manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts to our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counter-parties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a syndicated bank line of credit of $1,000 million as at December 31, 2009, and an additional credit facility of $500 million that was entered into on February 2, 2010. On February 3, 2010, the $1,000 million credit facility was reduced to $750 million. We have continued to issue sufficient cost-effective debt financing through the MTN Program and Commercial Paper Program in the Canadian debt markets to date despite the adverse economic conditions present at the beginning of 2009 and have sufficient available liquidity.

Pension

During 2009, the deferred pension asset reported on our balance sheet decreased by $17 million to $424 million. We contributed $112 million into our pension plan in 2009 and incurred $129 million in net periodic pension benefit cost. On an accounting basis, the 2008 unfunded benefit obligation of $171 million increased by $233 million to $404 million. The plan experienced positive returns of about 17.2% in the year. However, the plan was also impacted by an increase in the accrued benefit obligation primarily as a result of a decrease in the discount rate used for accounting purposes (see Critical Accounting Estimates – Employee Future Benefits).

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 of 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 reviewing of our risk profile and practices, and our Senior Vice-President and 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, are 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 Senior Vice-President and 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 influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008 the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi. In 2009, the Province required Hydro One, amongst other agencies, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Hydro One's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province 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 proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which could have a material adverse effect on our business.

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 earn the approved rates 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 materially 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 affected 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, to ensure that the targeted CDM accomplishments do not result in deteriorated revenues. 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 any such compensation mechanism is yet to be determined. We are also subject to risk of revenue loss from other factors.

In response to the GEA, we expect to make a significant investment in the coming years in large-scale transmission and distribution infrastructure projects, and to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The distribution systems have generally been built to accommodate one directional flow of electricity from the transmission system to customers' meters. Distributed generation connected to the distribution system requires the accommodation of two directional flows. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures. In addition, it is possible that we may not obtain all necessary regulatory approvals for these projects or if approvals are obtained, they may be subsequently challenged, appealed or overturned. This could impact our ability to recover costs already incurred in the planning and development of such projects.

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 asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2010 and 2013, including $600 million maturing in 2010 and $500 million maturing in 2011. We plan to incur capital expenditures of approximately $2.0 billion in 2010 and capital expenditures are expected to increase to approximately $2.1 billion in 2011. Cash generated from operations, after the payment of expected dividends, 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 materially 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 company.

Risk Associated with Transmission Projects

The amount of power which may flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our networks to reliably transmit power from new and existing generation sources (including, expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: (a) environmental approval(s) and (b) receipt of OEB approvals which can include expropriation and (c) appropriate consultation processes, and where appropriate, accommodation with First Nations and Métis who may be potentially affected by a project. Obtaining these approvals and carrying out these processes may also be impacted by public opposition to the proposed site of transmission investments, thus there is a risk that necessary approvals may not be obtained in a timely fashion or at all. This will adversely affect transmission reliability and/or our service quality, both of which could have a materially adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital and maintenance programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, including that opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities. Lead times for material and equipment have also increased substantially due to increased demand and limited vendor capability.

Adjustments to accommodate these external dependencies have been made in our planning. However, if we are unable to carry out these plans, in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Work Force Demographic Risk

By the end of 2009, more than 17% of our employees were eligible for retirement and by 2011 there may be more than 25% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We have already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions, to opportunities in other electricity sector positions across Canada (and, in particular, in Ontario) as well as senior positions outside of the sector. Moreover, we must also 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, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. We cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. 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 (LAR) program covering most of our stations and service centres. It involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

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.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's polychlorinated biphenyl (PCB) regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025 while our LAR expenditures are expected to be incurred over the period ending 2020. 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.

As a result of regulatory changes, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We plan on undertaking additional studies, using the assistance of external experts as required, to estimate the incremental expenditures associated with removing such materials prior to facility demolition. This information will allow us to reasonably estimate and record any obligation we may have to incur such expenditures. We also anticipate that such future expenditures will be recoverable in future electricity rates.

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, or governments decide to implement exposure limits, 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. Any of these could have a material adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. 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 transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possess inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss, we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

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 which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We continue to transition most of our financial and business processes to an integrated business and financial reporting system. The conversion of these systems and processes may expose us to risk, including risks associated with our ability to capture data and to produce timely and accurate information for downstream processing and to maintain internal controls. System failures or security breaches could have a material adverse effect on our company.

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 FSCO on a triennial basis. The most recently filed valuation was prepared as at December 31, 2006, and was filed in September 2007. The next valuation is required to be prepared as at December 31, 2009, and will be filed in September 2010. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on investment returns, changes in benefits or actuarial assumptions. Economic uncertainty and financial market volatility contributed to negative returns in 2008 of approximately 22.5%. In 2009, the pension plan has experienced positive overall investment returns of approximately 17.2%. The deficit position at the end of 2009 is not expected to result in any significant change in our contribution requirements beyond 2009. A determination by the OEB that some of our pension expenditures are not recoverable from customers would have a material adverse effect on our company.

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. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic 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 Businesses' net income by approximately $15 million and our Distribution Businesses' net income by approximately $10 million. Our net income is 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.

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 and by monitoring the financial condition of counter-parties. 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*. The failure to properly manage these risks could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost efficient manner. Although we believe that we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2011, and the existing Society of Energy Professionals collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, 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. Any of these could have a material adverse effect on our company.

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, 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 $822 thousand that we paid to these Indian bands and bodies in 2009. If we cannot obtain consents from the Indian bands and bodies, 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 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 our net income if we are not able to recover them in future rate orders.

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 the agreement with Inergi is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the functions involved, which could have a material adverse effect on our business, operating results, financial condition or prospects. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. 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 by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Changes in Accounting Policies

Corporate Income Taxes

Effective January 1, 2009, we adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* and CICA Handbook Section 1100, *Generally Accepted Accounting Principles*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, we recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Adjustments to retained earnings were recorded for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008, that are excluded from the rate-setting process.

Intangible Assets

Effective January 1, 2009, we adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which replaced CICA Handbook Section 3062, *Goodwill and Other Intangible Assets*, and CICA Handbook Section 3450, *Research and Development Costs*. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

As a result of adopting this new accounting standard, we reclassified computer applications software previously classified as fixed assets and reclassified other assets previously classified as long-term other assets to intangible assets.

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, 2009, amounted to $1,105 million and principally relate to future income tax, environmental costs and the rural rate protection variance account. We have also recorded regulatory liabilities amounting to $604 million as at December 31, 2009. These amounts pertain primarily to deferred pension, the regulatory liability refund account, future income tax, retail settlement variance accounts, and a regulatory asset recovery account (RARA I), which is currently in a liability position. 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. 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 satisfy 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 assets contaminated with PCB-laden 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, in order to generate future cash flow information. A long-term inflation assumption of 2% has been used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded. Consistent with the requirements of Environment Canada's PCB regulations issued on September 17, 2008, estimated future PCB expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded.

Recording a liability now 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; the number of assets to be inspected, tested and mitigated; oil volumes; and contamination levels of equipment with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future 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 were approximately $112 million in 2009, based on an actuarial valuation effective December 31, 2006. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on 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 7.25% 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 remained at 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 intended to be 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. In the short term, the plan can experience aberrations in actual return. In 2009, the return on pension plan assets was higher than this long-term assumption, but was lower in 2008.

The 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, 2009, decreased to 6.50% from 7.25% used at December 31, 2008, in conjunction with increases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

Yields on AA corporate bonds decreased by approximately 50–180 basis points between December 31, 2008, and December 31, 2009. Based on the duration of the plan's liabilities, discount rates would be 6.50% per annum for each of the pension plan, for the post-retirement benefit plan and for the post-employment plan. The overall discount rate applied to all plans for liability valuation purposes as at December 31, 2009, was 6.50%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has increased from approximately 1.30% per annum as at December 31, 2008, to approximately 2.50% per annum as at December 31, 2009. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is too high to be used as a long-term assumption, and as such, has used a 2.00% per annum inflation rate for liability valuation purposes as at December 31, 2009.

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 and an increase in the year-end obligation of about $141 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 and Asset Impairment

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 2009 and we determined that the carrying value of our goodwill has not been impaired.

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date for any of our businesses.

Status of Our Transition to International Financial Reporting Standards (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. In anticipation of this decision, we commenced our IFRS conversion project in 2007. The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a regular basis. An external expert advisor was engaged to assist with our IFRS conversion project.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high level review and identification of the major differences between current GAAP and IFRS in all subject areas, resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all policy papers. We are currently engaged in the implementation phase which is the final phase of our project. Our teams are continuing to monitor progress relative to key milestones, monitor developments of the International Accounting Standards Board (IASB), update recommendations and develop financial reports. We continue to have recurring dialogue with our external auditors about possible outcomes of our project. We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as necessary.

The areas with the highest potential to significantly impact our company, identified during the diagnostic phase, are rate-regulated assets and liabilities, fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1). The specific effects of choices under these standards are not determinable at this time as a result of the status of the IASB's project on rate-regulated activities which will have an impact on the accounting choices available in all of these areas.

In December 2008, the IASB added a project on rate-regulated activities to its agenda. In July 2009, the IASB issued an exposure draft detailing its proposals for standards for the accounting of rate-regulated activities. The exposure draft allows for the continued recognition of regulatory assets and liabilities on the Balance Sheet. In-scope assets and liabilities are proposed to be carried at the net present value of the expected future cash flows. The exposure draft makes an exception to the requirements of other IFRS standards by allowing capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the costs' inclusion in rate base. The IASB requested comments from interested observers on the exposure draft. Hydro One responded to the IASB's request for comment on November 24, 2009. The IASB received approximately 150 responses to its request for comment, which were very diverse in their opinions. As a result, the IASB staff has postponed presenting their analysis of the responses to the IASB, originally scheduled for January, to the Board's February meeting. The presentation to the IASB may include options for the next steps of the project. It is unclear at this time what the outcome of the IASB's deliberations will be and how reporting standards will be impacted.

The effect of the exposure draft on rate-regulated activities (RRA ED) will impact the determination of which indirect costs incurred on in-progress construction projects can be capitalized. This may affect our choices under IFRS 1. It is unclear at this time whether the continuation of accounting for expenditures related to employer sponsored pension plans on a cash basis would be permissible. Similarly, we are assessing our options with respect to the recognition of accumulated, unamortized gains and losses associated with employment benefits other than pension. Currently, the possible alternatives to account for these pension and other employee benefit amounts include charging unamortized gains and losses immediately upon adoption under IFRS 1, or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits*. Our policy choice is contingent upon the outcome of the RRA ED. In accordance with IAS 12, *Income Taxes*, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. If the RRA ED is adopted as is, we plan to continue to record taxes on a cash basis instead of the liability method for the regulated businesses.

On October 14, 2009, the Public Sector Accounting Board (PSAB) released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On December 14, 2009, the PSAB issued an exposure draft proposing to remove the requirement for government organizations adhering to IFRS to also apply additional public sector financial reporting standards, currently Public Sector Accounting Handbook Section 3270. The effective date for the proposed changes is January 1, 2011.

On September 25, 2009, the Canadian Securities Administrators' staff communicated their view that all registrants will be required to report under IFRS commencing January 1, 2011. We are a registrant as a result of our public debt.

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

Disclosure Controls and Internal Controls over Financial Reporting

In 2008, we began transitioning our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

In 2008, we successfully implemented the first phase of the supply chain, asset and work management modules in SAP. During the third quarter of 2009, we successfully implemented various finance, human resources, payroll and investment management SAP modules. The reporting tool Business Intelligence/Business Warehouse (BI/BW) was also implemented. This implementation included new controls over internal controls over financial reporting and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2009, 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 as at December 31, 2009. Further, our Certifying Officers have also certified that internal controls over financial reporting operated effectively as at December 31, 2009.

Selected Annual Information

The following table sets forth audited annual information for each of the three years ended December 31, 2007, 2008 and 2009. 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)	**2009**	2008	2007
Revenues[1]	**4,744**	4,597	4,655
Net income[1]	**470**	498	399
Basic and fully diluted earnings per common share	**4,528**	4,797	3,809

Consolidated Balance Sheet

Year ended December 31 (Canadian dollars in millions, except cash dividends per share)	**2009**	2008	2007
Total assets	**15,810**	13,878	12,786
Total long-term debt	**6,881**	6,133	5,603
Cash dividends per common share	**1,700**	2,410	3,070
Cash dividends per preferred share	**1.375**	1.375	1.375

[1] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008, reflecting growth in the work program requirements and investment in capital infrastructure.

Outlook

To achieve our vision to be the leading electricity delivery company in North America, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, innovation and connecting renewable energy, reliability, protection of the environment, recruitment and knowledge retention, shareholder value and productivity. We work in an environment where safety is of the utmost importance. Our people underpin everything we do, and as such, we remain resolute in our commitment to safety. We will continue to focus our efforts to improve our customers' satisfaction by maintaining operational excellence through our efforts to innovate and to renew transmission and distribution systems. In particular, we will focus on targeted investments to address overloaded or aging equipment at customer delivery points, power quality and network performance necessary to improve reliability, which will in turn, improve customer satisfaction.

The GEA introduced a new paradigm for Ontario's energy industry. The need to rapidly reduce the energy sector's carbon footprint dominates current environmental decision-making, leading to high expectation for immediate action and expansion of clean energy supply. Emerging technologies and the need to connect clean and renewable generation challenges our Transmission and Distribution Businesses to recalibrate and establish a more flexible and smart electricity grid.

We are planning significant investments in transmission and distribution infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability in the public interest. Our investment plan supports the achievement of the Province's coal shutdown, 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 2009, we filed a cost of service application with the OEB for 2010 and 2011 distribution rates, seeking revenue requirements of approximately $1,196 million and $1,295 million for 2010 and 2011, respectively. The revenue requirements requested, if approved, will continue to support our work programs necessary to sustain our critical infrastructure, increase reliability through enhanced forestry management, support the smart meter requirements and invest in a sustainable electricity system that supports renewable generation.

We are currently preparing evidence to support our upcoming transmission rate application for the years 2011 and 2012, which is anticipated to be filed with the OEB in the first quarter of 2010. This application will continue to support aging critical infrastructure, area supply projects and the Government policy objectives.

The actual timing and expenditures in our plan are predicated on obtaining various approvals including OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Further, we have made assumptions in the plan regarding cost responsibility and funding, consistent with the GEA regulations and amended TSC and DSC. We have prepared business plans, regulatory filings and future capital expenditures on the basis that rate-regulated accounting will continue under IFRS for the period commencing 2011.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and ensuring that environmental factors are considered in making our business decisions. Our commitment to the environment has been recognized by Canada's Energy, Environment and Excellence group and *Corporate Knights* magazine.

Key enablers of the successful implementation of our work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our association 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, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2009, the Government announced its intention to make the exemption from the electricity transfer tax permanent for transfers of electricity assets within the public sector. We have and will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. The investment plan does not include any funding for any LDC acquisitions or divestitures.

We will continue to increase enterprise value through productivity improvements and cost-effectiveness driven by technology. Over the last two years, we have replaced most of our core systems with an enterprise-wide information technology system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. In addition, significant opportunity resides with smart meters and the proliferation of a smart grid, including energy efficiency, demand response and distributed-resources technologies. Through the outlook period, we anticipate no changes to our role within the industry and expect that our financial returns will be sufficient to maintain our credit quality.

Appointment of George L. Cooke

On January 26, 2010, George L. Cooke was elected to our Board of Directors. Mr. Cooke is President and Chief Executive Officer of The Dominion of Canada General Insurance Company.

Forward Looking Statements and Information

Our oral and written public communications, including this document, 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 and our performance measures and targets; statements related to the IPSP; statements about smart meters including their capabilities, their timing of installation and our focus on building an advanced distribution solution that will leverage our smart meter investment; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of changes to codes, licences, rules, new regulatory guidelines, tariff rate changes, cost recovery, return on equity, rate structures, revenue requirements and impacts on an average customer's total bill; expectations regarding the timing and content of applications to, hearings with and decisions from the OEB and other regulatory bodies; expectations regarding our Green Energy Plan filed with the OEB and the impact of the GEA including future capital projects and cost recoveries flowing there from; expectations regarding future renewable energy generation; statements regarding our liquidity and capital resources and their use; expectations regarding our financing activities, including our capital management objectives and our ability to access the capital markets; expectations regarding the results of our on-going and planned projects and/or initiatives and their completion dates; statements regarding expected future capital expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commitments; statements regarding the effect of load on our revenue including the anticipated impact of CDM programs, embedded generation growth and the below-average growth of the Ontario economy; the effect of interest rates on our revenue requirements and results of operations; statements regarding the estimated impact of changes in the forecast long-term Government of Canada bond yield on our results of operations; impacts to our business in respect of the adequacy and timing of supply of materials, supplies and services and credit risk of our counter-parties; expectations regarding future pension contributions and the performance of our pension plan; the possibility of the Province making declarations pursuant to our memorandum of agreement with them; statements regarding possible future actions of the Province and regulatory bodies; expectations regarding connections of new generation to our transmission and distribution systems; expectations regarding asset condition; statements regarding workforce demographics and the market for skilled labour; statements regarding the amount and timing of future estimated environmental expenditures, including with respect to LAR and PCBs; statements about future asbestos removal expenditures; expectations regarding our information technology strategy and enterprise reporting system; the possibility that we could in future decide to issue foreign currency denominated debt; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements about our outsourcing arrangement with Inergi LP; statements regarding provincial ownership of our transmission corridors; statements about critical accounting estimates; statements about IFRS, our conversion to IFRS and the effect of the rate-regulated accounting exposure draft on our company; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, our credit rating and credit quality and structural changes to our company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," "goal," "aim," "target," 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 delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission Businesses; a stable regulatory environment; the preparation of business plans, regulatory filings and future capital expenditures on the basis that commencing 2011 rate-regulated accounting will continue to exist under IFRS; no unfavourable changes in environmental regulation; 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 sources. 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 impact of the GEA, including unexpected expenditures arising there from;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as, potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, cost recovery and rates, as well as, changes to rules under various regulatory body review;
- the potential impact of CDM programs on our load and our revenues;
- unanticipated changes in electricity demand or in our 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 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 that we will be unable to source the materials necessary to support our work programs;
- the risks related to our work force demographic and our potential inability to attract and retain qualified personnel;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risk of currently undetermined future asbestos removal costs;
- 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 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;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks associated with changes in interest rates;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- 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; and
- the impact of the final outcome of the exposure draft on rate-regulated accounting under IFRS.

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 (MD&A). You should review such section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to provide context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at February 11, 2010. 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 11, 2010.

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 National 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 KPMG 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 37, 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 Senior Vice-President 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 and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer

Sandy Struthers
Senior 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, 2009 and December 31, 2008, and the consolidated statements of operations and comprehensive income, retained earnings, accumulated other comprehensive income, and cash flows for the years then ended. 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 audit.

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, 2009 and December 31, 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
Chartered Accountants,
Licensed Public Accountants

Toronto, Canada
February 11, 2010

Consolidated Statements of Operations and Comprehensive Income

Year ended December 31 (Canadian dollars in millions, except per share amounts)	**2009**	2008
Revenues		
Transmission (Note 15)	**1,147**	1,212
Distribution (Note 15)	**3,534**	3,334
Other	**63**	51
	4,744	4,597
Costs		
Purchased power (Note 15)	**2,326**	2,181
Operation, maintenance and administration (Note 15)	**1,057**	965
Depreciation and amortization (Note 3)	**537**	548
	3,920	3,694
Income before financing charges and provision for payments in lieu of corporate income taxes	**824**	903
Financing charges (Note 4)	**308**	292
Income before provision for payments in lieu of corporate income taxes	**516**	611
Provision for payments in lieu of corporate income taxes (Notes 5 and 15)	**46**	113
Net income	**470**	498
Other comprehensive loss	**–**	(1)
Comprehensive income	**470**	497
Basic and fully diluted earnings per common share *(Canadian dollars)* (Note 14)	**4,528**	4,797

Consolidated Statements of Retained Earnings

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Retained earnings, January 1	**1,497**	1,258
Change in accounting policy for the recognition of future income tax assets and liabilities (Note 2)	**12**	–
Net income	**470**	498
Dividends (Note 14)	**(188)**	(259)
Retained earnings, December 31	**1,791**	1,497

See accompanying notes to Consolidated Financial Statements.

Consolidated Statements of Accumulated Other Comprehensive Income

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Accumulated other comprehensive income, January 1	**(10)**	(9)
Other comprehensive loss	**–**	(1)
Accumulated other comprehensive income, December 31	**(10)**	(10)

Consolidated Balance Sheets

December 31 (Canadian dollars in millions)	**2009**	2008
Assets		
Current assets:		
Cash	**–**	16
Accounts receivable (net of allowance for doubtful accounts – $25 million; 2008 – $23 million) (Note 15)	**843**	754
Regulatory assets (Note 8)	**72**	64
Materials and supplies	**21**	19
Future income tax assets (Notes 2 and 5)	**21**	2
Other	**16**	18
	973	873
Fixed assets (Notes 2 and 6):		
Fixed assets in service	**18,407**	17,334
Less: accumulated depreciation	**6,815**	6,418
	11,592	10,916
Construction in progress	**1,256**	912
Future use land, components and spares	**150**	132
	12,998	11,960
Other long-term assets:		
Deferred pension asset (Note 12)	**424**	441
Regulatory assets (Notes 2 and 8)	**1,033**	291
Goodwill	**133**	133
Intangible assets (net of accumulated amortization) (Notes 2 and 7)	**218**	162
Future income tax assets (Notes 2 and 5)	**18**	–
Other	**13**	18
	1,839	1,045
Total assets	**15,810**	13,878

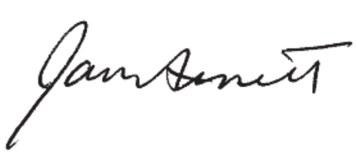
See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31 (Canadian dollars in millions)	**2009**	2008
Liabilities		
Current liabilities:		
Bank indebtedness	**26**	–
Accounts payable and accrued charges (Notes 13 and 15)	**800**	793
Regulatory liabilities (Notes 2 and 8)	**100**	43
Accrued interest	**74**	64
Short-term notes payable	**55**	–
Long-term debt payable within one year (Note 9)	**600**	400
	1,655	1,300
Long-term debt (Note 9)	**6,281**	5,733
Other long-term liabilities:		
Employee future benefits other than pension (Note 12)	**940**	908
Regulatory liabilities (Notes 2 and 8)	**504**	564
Future income tax liabilities (Notes 2 and 5)	**693**	–
Environmental liabilities (Note 13)	**303**	237
Long-term accounts payable and other liabilities	**16**	12
	2,456	1,721
Total liabilities	**10,392**	8,754
Contingencies and commitments (Notes 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	**1,791**	1,497
Accumulated other comprehensive income	**(10)**	(10)
Total shareholder's equity	**5,418**	5,124
Total liabilities and shareholder's equity	**15,810**	13,878

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:



James Arnett
Chair

Walter Murray
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Operating activities		
Net income	**470**	498
Environmental expenditures	**(9)**	(14)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	**487**	502
Revenue difference deferral account	**–**	(73)
Regulatory liability refund account	**(24)**	30
Smart meters	**(16)**	1
External revenue variance account	**12**	–
Revenue recovery account	**7**	(25)
Other regulatory asset and liability accounts	**(13)**	6
Future income taxes	**16**	–
Amortization of debt costs	**–**	2
	930	927
Changes in non-cash balances related to operations (Note 16)	**(38)**	125
Net cash from operating activities	**892**	1,052
Financing activities		
Long-term debt issued	**1,150**	1,050
Long-term debt retired	**(400)**	(540)
Short-term notes payable	**55**	–
Dividends paid	**(188)**	(259)
Other	**2**	3
Net cash from financing activities	**619**	254
Investing activities		
Capital expenditures		
Fixed assets	**(1,473)**	(1,185)
Intangible assets	**(93)**	(99)
	(1,566)	(1,284)
Other assets	**13**	6
Net cash used in investing activities	**(1,553)**	(1,278)
Net change in cash and cash equivalents	**(42)**	28
Cash and cash equivalents, January 1	**16**	(12)
Cash and cash equivalents, December 31 (Note 16)	**(26)**	16

See accompanying notes to Consolidated Financial Statements.

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 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 Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Inc. (HODS), Hydro One Lake Erie Link Management Inc. (HOLELMI) and Hydro One Lake Erie Link Company Inc. (HOLELCo).

HODS was dissolved on August 29, 2008. Effective December 13, 2007, upon approval of the resolution to apply for the dissolution of HODS, its interests in HOLELMI and HOLELCo were distributed to Hydro One.

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 Ontario Energy Board (OEB).

Transmission

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 revenue difference deferral account (RDDA), the earnings sharing mechanism (ESM) and export and wheeling fees, as well as the transmission market ready regulatory asset.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007, the OEB approved Uniform Transmission Rates (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.

On May 30, 2008, Hydro One Networks submitted an application to the OEB to adjust UTRs effective January 1, 2009. On August 28, 2008, the OEB approved the application allowing Hydro One Networks to recover revenues consistent with the OEB-approved 2008 revenue requirement, which reflected the full repayment to customers of the amounts recorded in the ESM and the RDDA at the end of 2008.

To achieve the necessary funding in support of required infrastructure, Hydro One Networks filed a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirement of approximately $1,233 million and $1,341 million, based on a return on equity of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision in respect of this application. The decision, which was effective July 1, 2009, resulted in a reduced revenue requirement of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved return on equity. The OEB decision disallowed development capital expenditures of $180 million for 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, Hydro One Networks filed the additional evidence on two projects amounting to approximately $160 million in capital expenditures. The OEB approved the supplemental evidence for inclusion in Hydro One Networks' 2010 rates. This resulted in a revised revenue requirement of $1,257 million for 2010, on the basis of an updated return on equity of 8.39% for 2010.

Distribution

In 2006, the OEB initiated a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process included a formulaic approach to establishing 2007 rates with a rate re-basing approach to be staggered across all Ontario distributors between 2008 and 2010.

In accordance with the OEB's multi-year distribution rate-setting plan, Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application on August 15, 2007. This application sought the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64%, and included 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.

On December 18, 2008, the OEB issued a decision approving substantially all work program expenditures effective May 1, 2008, for implementation on February 1, 2009. The OEB also approved recovery of our smart meter expenditures made prior to the end of 2007. The decision approved the establishment of the revenue recovery account (RRA) to record the revenue differential between existing distribution rates and new rates. The RRA is being recovered over a 27-month period commencing February 1, 2009 and ending April 30, 2011.

In late 2008, Hydro One Networks filed an incentive regulation application for 2009 rates, with an update filed in January 2009, to reflect the impact of the 2008 distribution rate decision. The application was filed on the basis of the OEB's third generation IRM process which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision approving the basic IRM increase and the $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009.

On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's second generation IRM policy which incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 19, 2008, the OEB released its decision. The revised rates, including an amount of $0.67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008.

On November 7, 2008, Hydro One Brampton filed an application on the same basis for 2009 distribution rates. On March 13, 2009, the OEB released it decision and approved the submission on the basis of its second generation IRM policy. The revised rates, including an amount of $1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009.

On August 29, 2008, Hydro One Remote Communities filed a 2009 cost of service rate application proposing an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all work program expenditures effective May 1, 2009.

Regulatory Accounting

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, 2009, amounted to $434 million (2008 – $383 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.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* and CICA Handbook Section 1100, *Generally Accepted Accounting Principles*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Adjustments to retained earnings were recorded for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the statement of operations and comprehensive income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the “more likely than not” criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Materials and Supplies
Materials and supplies represent consumables, 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; major components and spare parts; 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 in perpetuity, no asset retirement obligation exists. If, at some future date, a particular site is shown not to meet the perpetuity assumption, it will be reviewed to determine if an asset retirement obligation exists. If 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 and Development 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 and intangible assets under development, based on the OEB's approved allowance for funds used during construction (2009 – 5.89%; 2008 – 5.32%).

Depreciation and Amortization
The capital costs of fixed assets and intangible assets, primarily consisting of applications software, are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically undergoes an external review of its fixed asset and intangible depreciation and amortization rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation and amortization rates for the various classes of assets is included below:

	Depreciation and Amortization Rates (%)	
	Range	Average
Transmission	1%–3%	2%
Distribution	1%–13%	2%
Communication	1%–13%	5%
Administration and service	1%–20%	7%

The costs of intangible assets are primarily included within the administration and service classification above and these assets are amortized on a straight-line basis. Amortization rates for computer applications software and other assets range from 9% to 11%.

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 or amortization, 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 or amortization expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed or intangible 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.

Intangible Assets

Intangible assets represent computer applications software and other assets. These assets are carried at cost net of accumulated amortization. The cost of computer applications is comprised of materials, labour, overheads and the OEB-approved allowance for funds used during construction applicable to development activities within the regulated businesses.

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which replaced CICA Handbook Section 3062, *Goodwill and Other Intangible Assets* and CICA Handbook Section 3450, *Research and Development Costs*. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

As a result of adopting this new accounting standard, the Company reclassified computer applications software previously classified as fixed assets and reclassified other assets previously classified as long-term other assets to intangible assets.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Financial Instruments

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 to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the hedged debt.

Financial Assets and Liabilities

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:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Short-term investments	Held-to-maturity/Held-for-trading
Fixed-to-floating interest rate swap	Not classified
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Accounts payable	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (unless otherwise specified)	Other liabilities
MTN Series 14 Note	Not classified

Short-term investments are generally classified as held-to-maturity; however, the Company allows itself the possibility to classify pools of short-term investments as held-for-trading where there is not the intention of holding a pool of assets to their maturity. Documentation of the short-term investment classification is made on inception.

Where long-term debt is designated as part of a hedging relationship, as in the case of the MTN Series 14 Note, the long-term debt, and related hedging instrument, are not classified.

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 or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. 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 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 documentation includes its risk management objective for establishing the hedging relationship, the identification of hedged and hedging item, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items.

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.

Financial Instrument Disclosures

Effective for the 2009 annual reporting period, the Company adopted amendments to the CICA Handbook Section 3862, *Financial Instruments Disclosure*. This amended section improves financial instrument fair value measurement and liquidity risk management disclosures. The amendments require an entity to classify fair value measurements using a fair value hierarchy in levels ranging from 1 to 3 that reflect the significance of the inputs used in making these measurements. The amendments also provide clarification about the required liquidity risk disclosures. Upon application by the Company, the fair value hierarchy level used in the determination of the fair market value of the long-term debt has been disclosed in Note 10.

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 records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyls (PCBs) contaminated mineral oil removed from electrical equipment, based on the 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 recorded 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.

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. As such, the Company will apply IFRS to its financial statements ending December 31, 2011, with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The International Accounting Standards Board (IASB) issued an exposure draft on rate-regulated activities in July 2009. Responses to the IASB's request for comment varied substantially. As a result, the IASB staff has postponed presenting their analysis of the responses to the IASB until February 2010. This presentation may include options for the next steps of the rate-regulated activities project. It is unclear at this time what the outcome of the Board's deliberations will be and how that will impact the Company's reporting under IFRS. The effect on the Company's future financial position and results of operations are not estimable at this time.

3. Depreciation and Amortization

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Depreciation of fixed assets in service	**418**	404
Amortization of intangible assets	**36**	14
Fixed asset removal costs	**50**	46
Amortization of regulatory and other assets	**33**	84
	537	548

4. Financing Charges

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Interest on short-term notes payable	**–**	2
Interest on long-term debt payable	**369**	331
Interest accreted on regulatory accounts	**1**	2
Less: Interest capitalized on construction and development in progress	**(58)**	(36)
Interest earned on investments	**(1)**	(7)
Other	**(3)**	–
	308	292

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. The reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Income before provision for PILs	**516**	611
Federal and Ontario statutory income tax rate	**33.00%**	33.50%
Provision for PILs at statutory rate	**170**	205
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Transmission amounts paid but not recognized for accounting purposes	**–**	(34)
Capital cost allowance in excess of depreciation and amortization	**(74)**	(32)
Retail settlement variance accounts	**4**	15
Pension contributions in excess of pension expense	**(15)**	(13)
Overheads capitalized for accounting but deducted for tax purposes	**(14)**	(12)
Interest capitalized for accounting purposes but deducted for tax purposes	**(19)**	(11)
Distribution amounts paid but not recognized for accounting purposes	**–**	(8)
Employee future benefits other than pension expense in excess of cash payments	**1**	6
Environmental expenditures	**(3)**	(5)
Other	**(6)**	–
Net temporary differences	**(126)**	(94)
Net permanent differences	**2**	2
Total income tax provision for PILs	**46**	113
Current income tax provision for PILs	**30**	113
Future income tax provision for PILs	**16**	–
Total income tax provision for PILs	**46**	113
Effective income tax rate	**8.91%**	18.49%

The provision for payments in lieu of current income taxes of $30 million represents the amount payable to the OEFC with respect to current year earnings. There is no outstanding balance due to the OEFC (2008 – $nil).

The provision for payments in lieu of future income taxes of $16 million reflects the increase in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Company's customers through future rates. The increase in the liability for payments in lieu of future income taxes that is expected to be recovered from the Company's customers through future rates has resulted in an increase in regulatory assets.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in millions)	2009
Future income tax assets	
Capital cost allowance in excess of depreciation and amortization	6
Employee future benefits other than pension expense in excess of cash payments	4
Retail settlement variance accounts	3
Environmental expenditures	3
Other	3
Total future income tax assets	19
Less: current portion	1
	18

December 31 (Canadian dollars in millions)	2009
Future income tax liabilities	
Capital cost allowance in excess of depreciation and amortization	(1,019)
Employee future benefits other than pension expense in excess of cash payments	315
Environmental expenditures	82
Transmission and distribution amounts received but not recognized for accounting purposes	(73)
Goodwill	25
Retail settlement variance accounts	5
Other	(8)
Total future income tax liabilities	(673)
Less: current portion	20
	(693)

As at December 31, 2009, payments in lieu of future income tax liabilities of $461 thousand (2008 – $4 million), based on substantively enacted income tax rates and laws, have not been recorded, as it is more likely than not that the assets will not be realized in the future.

6. Fixed Assets

December 31 (Canadian dollars in millions)	Fixed Assets	Accumulated Depreciation	Construction in Progress	Total
2009				
Transmission	**9,485**	**3,455**	**956**	**6,986**
Distribution	**6,773**	**2,392**	**220**	**4,601**
Communication	**806**	**376**	**54**	**484**
Administration and service	**1,007**	**510**	**26**	**523**
Easements	**486**	**82**	**–**	**404**
	18,557	**6,815**	**1,256**	**12,998**
2008				
Transmission	8,995	3,307	659	6,347
Distribution	6,317	2,266	165	4,216
Communication	773	342	54	485
Administration and service	894	426	34	502
Easements	487	77	–	410
	17,466	6,418	912	11,960

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 $55 million in 2009 (2008 – $33 million).

7. Intangible Assets

December 31 (Canadian dollars in millions)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2009				
Computer applications software	**379**	**166**	**3**	**216**
Other assets	**5**	**3**	**–**	**2**
	384	**169**	**3**	**218**
2008				
Computer applications software	270	162	51	159
Other assets	5	2	–	3
	275	164	51	162

Financing costs are capitalized on intangible assets under development, including allowance for funds used during construction on regulated assets, and were $3 million in 2009 (2008 – $3 million).

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:

December 31 (Canadian dollars in millions)	**2009**	2008
Regulatory assets:		
Regulatory future income tax asset	**683**	–
Environmental	**327**	253
Rural and remote rate protection variance account	**24**	17
Regulatory asset recovery account II	**19**	43
Smart meters	**19**	3
Revenue recovery account	**18**	25
Other	**15**	14
Total regulatory assets	**1,105**	355
Less: current portion	**72**	64
	1,033	291

December 31 (Canadian dollars in millions)	**2009**	2008
Regulatory liabilities:		
Deferred pension	**424**	441
Regulatory liability refund account	**49**	73
Regulatory future income tax liability	**32**	–
Retail settlement variance accounts	**29**	31
Regulatory asset recovery account I	**23**	19
Export and wheeling fees	**15**	27
External revenue variance account	**12**	–
Other	**20**	16
Total regulatory liabilities	**604**	607
Less: current portion	**100**	43
	504	564

Regulatory Assets

Regulatory Future Income Tax Asset and Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts set up for taxes to be recovered through future rates. As a result the provision for PILs would have been higher by approximately $127 million (2008 – $79 million) including the impact of a change in substantively enacted tax rates.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2008, this regulatory asset increased by $195 million to reflect the additional liability recorded in respect of the issuance of Environment Canada's final PCB regulations. In 2009, the regulatory asset increased by $30 million to reflect related increases in the Company's PCB liability and by $40 million for an increase in the land assessment and remediation (LAR) liability.

The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been higher by $70 million (2008 – $195 million). In addition, amortization expense in 2009 would have been lower by $9 million (2008 – $14 million) and financing charges would have been higher by $13 million (2008 – $7 million).

Rural and Remote Rate Protection Variance Account (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. In 2002, the OEB approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account to be disposed of at a later date.

Regulatory Asset Recovery Account II (RARA II) or Rider 2

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 2009 would have been lower by $23 million (2008 – $23 million). In addition, related financing charges would have remained the same (2008 – higher by $2 million).

Smart Meters

On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and approved a monthly rate adder charge of $0.27 and $0.28 cents per residential metered customer for Hydro One Networks and Hydro One Brampton, respectively. The Company recorded a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder. Effective May 1, 2007, the OEB increased the monthly adder to $0.93 cents and $0.67 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively.

On August 8, 2007, the OEB issued its decision allowing certain expenditures incurred by Hydro One Networks and Hydro One Brampton associated with minimum functionality for advanced metering infrastructure to be recovered and allowing certain capital expenditures to be included in rate base. As a result of this decision, the Company discontinued recording its smart meter expenditures as regulatory assets and instead began recording such expenditures as capital expenditures or as operation, maintenance and administration costs as appropriate. This OEB decision also required that revenues for smart meter expenditures not yet reviewed and approved, be recorded based upon a calculated revenue requirement in the same regulatory deferral account as amounts received under the approved smart meter rate adders. As a result, the difference between revenue recorded on this basis and actual recoveries received under existing rate adders is reflected as the carrying value of the regulatory asset account.

On December 18, 2008, as part of the OEB's decision on 2008 distribution rates, the OEB approved the recovery of certain excess functionality expenditures and the under-recovery of smart meter minimum functionality expenditures (revenue requirement net of revenue received from the monthly rate adder). The expenditures related to excess functionality are being recovered through the regulatory liability refund account.

Effective May 1, 2009, the OEB increased the respective monthly rate adders for Hydro One Brampton and Hydro One Networks' residential customers to $1.00 and $1.65 per month per metered customer. Hydro One Networks, as part of its application for 2010 and 2011 distribution rates, has requested the approval for the disposition of costs exceeding minimum functionality and the under-recovery of smart meter minimum functionality expenditures (revenue requirement net of revenue received from the monthly rate adder) through to December 31, 2008.

Revenue Recovery Account (RRA) or Rider 4

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. The approved rates were effective May 1, 2008, with an implementation date of February 1, 2009. The OEB approved the establishment of the RRA to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through a rate rider, over a period of 27 months commencing February 1, 2009, and ending April 30, 2011.

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 $9 million (2008 – lower by $38 million).

Regulatory Liability Refund Account (RLRA) or Rider 3

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of the decision, the OEB also approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance amounts, deferred tax changes, OEB costs and smart meters. Amounts for which recovery was approved represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011.

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 RSVA accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of RSVA accumulated since January 1, 2004, and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The OEB's December 18, 2008 decision allowed for recovery of RSVA accumulated since May 1, 2006 through to April 30, 2008, inclusive of interest, within the RLRA. Hydro One Networks has accumulated a net liability in its RSVA since May 1, 2008.

Regulatory Asset Recovery Account I (RARA I) or Rider 1

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 included 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. Hydro One Networks has accumulated a net liability in its RARA I account since May 1, 2008, due to continuance of the rate rider. In the absence of rate-regulated accounting, amortization expense in 2009 would have remained the same (2008 – lower by $5 million).

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 Networks' Transmission Business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 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.

External Revenue Variance Account

On May 28, 2009, the OEB issued its decision regarding the 2009 and 2010 rates for the Transmission Business of Hydro One Networks. As part of the decision, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use and external revenue from station maintenance and engineering and construction work. These revenue sources are an offset to the Company's revenue requirement, and as such, the OEB requested the establishment of new variance accounts to capture any difference between the forecasted and actual revenues from these sources of external revenue. The balance reflects the excess of 2009 external revenue compared to the OEB-approved forecast.

9. Debt

December 31 (Canadian dollars in millions)	**2009**	2008
Long-term debt:		
3.95% notes due 2009	**–**	400
7.15% debentures due 2010	**400**	400
3.89% notes due 2010	**200**	100
4.08% notes due 2011[1]	**250**	250
6.40% notes due 2011	**250**	250
5.77% notes due 2012	**600**	600
5.00% notes due 2013	**600**	400
3.13% notes due 2014	**250**	–
4.64% notes due 2016	**450**	450
5.18% notes due 2017	**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	**600**	600
4.89% notes due 2037	**400**	400
6.03% notes due 2039	**300**	–
5.49% notes due 2040	**300**	–
6.59% notes due 2043	**315**	315
5.00% notes due 2046	**75**	75
	6,875	6,125
Add: Unrealized hedged loss[1]	**11**	15
Less: Long-term debt payable within one year	**(600)**	(400)
Net unamortized premiums	**24**	20
Unamortized debt issuance costs	**(29)**	(27)
Long-term debt	**6,281**	5,733

[1] The unrealized hedged loss relates to the MTN Series 14 Note, which is accounted for as a fair value hedge. The unrealized hedged loss is offset by the $11 million (2008 – $15 million) unrealized gain on the related fixed-to-floating interest rate swap agreement.

Short-term debt represents promissory notes pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2009, the notes had a weighted average interest rate of 0.3%.

Hydro One has a $1,000 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 (MTN) Program. On November 19, 2009, Hydro One issued new notes comprised of medium-term notes with a principal amount of $250 million having a five-year term and a coupon rate of 3.13%. The notes are due November 19, 2014.

The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million, of which, as at December 31, 2009, $2,750 million was remaining.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in Note 10.

10. Carrying and Fair Value of Financial Instruments and Risk Management

The carrying value of financial instruments as at December 31, 2009 is as follows:

(Canadian dollars in millions)	Derivatives Used for Hedging	Other Financial Instruments Used for Hedging	Held-for-Trading	Loans and Receivables	Other Financial Liabilities
Financial assets					
Accounts receivable	–	–	–	843	–
Other assets (long-term)	11	–	–	2	–
Financial liabilities					
Bank indebtedness	–	–	–	–	26
Accounts payable and accrued charges[1]	–	–	–	–	795
Short-term notes payable	–	–	–	–	55
Long-term debt	–	261	–	–	6,620

[1] Accounts payable and accrued charges do not include income taxes payable or dividends payable.

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, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in millions)		**2009**		2008
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**6,875**	**7,302**	6,125	6,128

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the MTN Series 14 Note, which is designated as part of a hedging relationship.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency denominated debt which will be hedged back to Canadian dollars consistent with Hydro One's risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution and Transmission Businesses is derived using a formulaic approach which is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A" rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecast long-term Government of Canada bond yield or the "A" rated Canadian utility spread used in determining the Company's rate of return would reduce its Transmission Business' results of operations by approximately $15 million and its Distribution Business' results of operations by approximately $10 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2009, 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 individual customer. As at December 31, 2009, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts remained relatively unchanged at $25 million (2008 – $23 million). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2009, approximately 4% of the Company's accounts receivable were aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques including entering into transactions with highly rated counter-parties; limiting total exposure levels with individual counter-parties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counter-parties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest rate risk. 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. No such agreements were outstanding as at December 31, 2009.

Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at December 31, 2009, the only derivative instrument held by Hydro One was a $250 million fixed-to-floating interest rate swap agreement to convert the 4.08% coupon note maturing March 3, 2011, into a three-month variable rate debt. The counter-party credit risk exposure on the fair value of this interest rate swap contract is $11 million as at December 31, 2009.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations and the Company's Commercial Paper Program, under which it is authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days. The Commercial Paper Program is supported by committed revolving credit facilities with a syndicate of banks of $1,000 million as at December 31, 2009, maturing August 20, 2010. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2009, accounts payable and accrued charges in the amount of $800 million and the short-term notes payable in the amount of $55 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next 12 months is $600 million. Interest payments over the next 12 months on the Company's outstanding short-term notes payable and long-term debt amount to $372 million.

As at December 31, 2009, Hydro One has issued long-term debt in the amount of $6,875 million and the Company is required to make interest payments in the amount of $5,967 million. Principal outstanding, interest payments and related weighted average interest rates are 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)*	Interest Payments *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	600	372	6.1
2 years	500	345	5.2
3 years	600	324	5.8
4 years	600	289	5.0
5 years	250	259	3.1
	2,550	1,589	5.3
6–10 years	1,050	1,121	4.9
Over 10 years	3,275	3,257	6.1
	6,875	5,967	5.6

11. Capital Management

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, short-term notes payable, long-term debt and cash and cash equivalents. The Company's capital structure as at December 31, 2009 and December 31, 2008 was as follows:

(Canadian dollars in millions)	**2009**	2008
Short-term notes payable	**55**	–
Long-term debt payable within one year	**600**	400
Less: Cash and cash equivalents	**(26)**	16
	681	384
Long-term debt	**6,281**	5,733
Preferred shares	**323**	323
Common shares	**3,314**	3,314
Retained earnings	**1,791**	1,497
	5,428	5,134
Total capital	**12,390**	11,251

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2009, Hydro One is in compliance with all of these covenants and limitations.

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 Asset Mix

Hydro One's pension plan asset mix at December 31, 2009 and 2008 was as follows:

	% of Plan Assets	
December 31	**2009**	2008
Equity securities	**63.3**	62.0
Debt securities	**32.9**	33.3
Other	**3.8**	4.7
	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 $88 million at December 31, 2009 and 2008.

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 with the Financial Services Commission of Ontario (FSCO) on September 20, 2007, effective for December 31, 2006, the Company contributed $112 million to its pension plan in respect of 2009 (2008 – $101 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 2009, 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 $155 million (2008 – $142 million).

Pension Asset Transfer

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP (Inergi), including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi. On March 10, 2008, the Company was granted consent from the FSCO to transfer pension assets and related pension liabilities for affected employees from the Hydro One Pension Plan to the Inergi Pension Plan. Under the agreement, the Company recognized a settlement of $21 million in its results of operations for the first quarter of 2008, inclusive of a related interest credit of $6 million. The pension asset transfer took place in the second quarter of 2008.

	Pension		Employee Future Benefits Other Than Pension	
Year ended December 31 (Canadian dollars in millions)	**2009**	2008	**2009**	2008
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**4,007**	5,077	**874**	1,094
Current service cost	**73**	98	**19**	22
Interest cost	**286**	277	**63**	60
Benefits paid	**(270)**	(272)	**(43)**	(41)
Plan amendments	**–**	–	**–**	–
Net actuarial loss (gain)	**644**	(1,173)	**91**	(261)
Accrued benefit obligation, December 31	**4,740**	4,007	**1,004**	874
Change in plan assets				
Fair value of plan assets, January 1	**3,836**	5,100	**–**	–
Actual return on plan assets	**642**	(1,121)	**–**	–
Reciprocal transfers[2]	**6**	21	**–**	–
Benefits paid	**(270)**	(272)	**–**	–
Employer's contributions[1]	**112**	101	**–**	–
Employees' contributions	**21**	20	**–**	–
Administrative expenses	**(11)**	(13)	**–**	–
Fair value of plan assets, December 31	**4,336**	3,836	**–**	–
Funded status				
Unfunded benefit obligation	**(404)**	(171)	**(1,004)**	(874)
Unamortized net actuarial losses (gains)	**814**	594	**10**	(92)
Unamortized past service costs	**14**	18	**14**	18
Deferred pension asset (accrued benefit liability)	**424**	441	**(980)**	(948)
Less: current portion	**–**	–	**40**	40
Deferred pension asset (long-term liability)	**424**	441	**(940)**	(908)

[1] In January 2010, the Company made a contribution of $10 million in respect of 2009 (2009 – $10 million in respect of 2008).

[2] In August 2008, the Hydro One Pension Plan received $21 million in reciprocal transfers, of which $19 million represents a reciprocal transfer of assets from the Inergi Pension Plan.

		Pension	Employee Future Benefits Other Than Pension	
Year ended December 31 (Canadian dollars in millions)	**2009**	2008	**2009**	2008
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**52**	78	**19**	22
Interest cost	**286**	277	**63**	60
Actual return on plan asset net of expenses	**(631)**	1,113	**–**	–
Actuarial loss (gain)	**644**	(1,173)	**91**	(261)
Other	**(1)**	–	**–**	–
Costs arising in the period	**350**	295	**173**	(179)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**359**	(1,465)	**–**	–
Actuarial (gain) loss	**(584)**	1,206	**(101)**	269
Plan amendments	**4**	4	**4**	4
Net periodic benefit cost	**129**	40	**76**	94
Charged to results of operations[3]	**68**	63	**50**	57
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**141**	108
Service cost and interest cost	**–**	–	**13**	14
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**(113)**	(88)
Service cost and interest cost	**–**	–	**(10)**	(11)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**7.25%**	7.00%	**–**	–
Weighted average discount rate	**7.25%**	5.50%	**7.25%**	5.50%
Rate of compensation scale escalation (without merit)	**2.75%**	3.00%	**2.75%**	3.00%
Rate of cost of living increase	**2.00%**	2.25%	**2.00%**	2.25%
Average remaining service life of employees *(years)*	**10**	10	**11**	11
Rate of increase in health care cost trend[4]	**–**	–	**4.81%**	4.40%
For accrued benefit obligation, December 31:				
Weighted average discount rate	**6.50%**	7.25%	**6.50%**	7.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.75%	**2.50%**	2.75%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Rate of increase in health care cost trend[5]	**–**	–	**4.81%**	4.81%

[3] The Company follows the cash basis of accounting. During 2009, pension costs of $113 million (2008 – $103 million) were attributed to labour, of which $68 million (2008 – $63 million) was charged to operations and $45 million (2008 – $40 million) was capitalized as part of the cost of fixed assets.

[4] 8.81% in 2009 grading down to 4.81% per annum in and after 2029 (2008 – 8.33% in 2008 grading down to 4.40% per annum in and after 2018).

[5] 8.57% in 2010 grading down to 4.81% per annum in and after 2029 (2008 – 8.81% in 2009 grading down to 4.81% per annum in and after 2023).

13. Environmental Liabilities

December 31 (Canadian dollars in millions)	**2009**	2008
Environmental liabilities, January 1	**253**	65
Interest accretion	**13**	7
Expenditures	**(9)**	(14)
Revaluation adjustment	**70**	195
Environmental liabilities, December 31	**327**	253
Less: current portion	**(24)**	(16)
	303	237

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2009, and in total thereafter are as follows: 2010 – $24 million; 2011 – $34 million; 2012 – $34 million; 2013 – $42 million; 2014 – $37 million and thereafter – $218 million.

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The Company's liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations.

There are uncertainties in estimating future environmental costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on criteria including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except specified equipment, had to be disposed of by the end of 2009. However, in 2009, Hydro One sought and received an extension until 2014 for removal of certain station equipment that could be contaminated in excess of this threshold. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or more than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025. In addition, liquids with 2 ppm or more that have been removed from equipment cannot be reused.

Management judges that the Company has very limited PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets that must be compliant by 2014. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retrofilling with less than 2 ppm replacement oil.

Management's best estimate of the total estimated future expenditures to comply with PCB regulations is about $320 million. These expenditures will be incurred over the period from 2010 to 2025. As a result of its most recent cost estimate to comply with Environment Canada's PCB regulations and Environment Canada interpretations thereof, the Company has increased its December 31, 2009 environmental liability by approximately $30 million compared to September 30, 2009.

LAR

As a result of 2009 changes to provincial regulations governing land contamination mitigation and changes in acceptable regulated contamination thresholds, as well as other factors, the Company reviewed its liability for contaminated LAR. As a result of this review, the Company recorded a $40 million increase in its related liability, as compared to September 30, 2009. The Company's best estimate of the total future expenditures to complete its LAR program is about $69 million. As part of its review, the Company extended the term of its planned program for distribution properties from 2013 to 2020 and for transmission properties from 2015 to 2020.

Asbestos-Containing Materials

As a result of regulatory changes, Hydro One expects to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of its facilities. The Company plans to undertake additional studies, using the assistance of external experts as required, to estimate the incremental expenditures associated with removing such materials prior to facility demolition. This information will allow the Company to reasonably estimate and record any obligation it may have to incur such expenditures. The Company also anticipates that such future expenditures will be recoverable in future electricity rates.

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 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 2009, preferred dividends in the amount of $18 million (2008 – $18 million) and common dividends in the amount of $170 million (2008 – $241 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.

15. Related Party Transactions

The Province, OEFC, IESO, Ontario Power Authority (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 UTRs approved by the OEB. Transmission revenue for 2009 includes $1,119 million (2008 – $1,072 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2009 includes $127 million (2008 – $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 2009 includes $31 million (2008 – $21 million) related to these services.

In 2009, Hydro One purchased power in the amount of $2,296 million (2008 – $2,128 million) from the IESO administered electricity market, $19 million (2008 – $35 million) from OPG and $11 million (2008 – $18 million) from OEFC.

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 2009, Hydro One incurred $10 million (2008 – $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 $13 million (2008 – $12 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 $2 million (2008 – $1 million).

The OPA funds some of our Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2009, Hydro One received $23 million from the OPA in respect of the CDM programs (2008 – $11 million) and had a net accounts receivable of $1 million (2008 – $6 million).

The provision for payments in lieu of corporate income taxes, property taxes and capital 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)	**2009**	2008
Accounts receivable	**103**	103
Accounts payable and accrued charges	**(250)**	(260)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $211 million (2008 – $225 million).

16. Consolidated Statements of Cash Flows

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash" and "bank indebtedness." The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Accounts receivable (increase) decrease	**(89)**	5
Materials and supplies (increase) decrease	**(2)**	4
Accounts payable and accrued charges increase	**–**	58
Accrued interest increase	**10**	9
Long-term accounts payable and other liabilities increase (decrease)	**4**	(1)
Employee future benefits other than pension increase	**32**	53
Other	**7**	(3)
	(38)	125

Supplementary information:

Interest paid	**361**	330
Payments in lieu of corporate income taxes	**77**	145

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 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 Superior Court of 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 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 the Whitesand First Nation Band and the Red Rock First Nation Band are set out. These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The claims arise out of flooding activities of Ontario Hydro and the alleged effects of flooding on lands in which the two First Nations claim an interest. By an agreement dated May 2009, all parties entered into an agreement to dismiss all of the actions against Hydro One without costs.

Transfer of Assets

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, 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 annually more than the $822,000 that we paid to these Indian bands and bodies in 2009. If we cannot obtain consents from the Indian bands and bodies, 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 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 our net income if we are not able to recover them in future rate orders.

18. Commitments

Agreement with Inergi

Effective March 1, 2002, Inergi LP (a wholly owned subsidiary of Cap Gemini Canada Inc.) began providing services to Hydro One. 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. Inergi billing for these services has ranged between $93 million and $130 million per year and is 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, 2009, and in total thereafter are as follows: 2010 – $104 million; 2011 – $101 million; 2012 – $17 million; 2013 – $nil; 2014 – $nil and thereafter – $nil. The agreement expires on February 29, 2012.

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. As at December 31, 2009 and December 31, 2008, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton using only parental guarantees of $325 million (2008 – $325 million). Prudential support at December 31, 2009, was also provided on behalf of two distributors using guarantees of $660 thousand (2008 – $nil). The IESO could draw on these guarantees if these subsidiaries or distributors fail 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. 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.

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, 2009, Hydro One had bank letters of credit of $107 million (2008 – $107 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, 2009, and in total thereafter are as follows: 2010 – $9 million; 2011 – $5 million; 2012 – $7 million; 2013 – $6 million; 2014 – $6 million and thereafter – $26 million.

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.

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
2009				
Segment profit				
Revenues	**1,147**	**3,534**	**63**	**4,744**
Purchased power	**–**	**2,326**	**–**	**2,326**
Operation, maintenance and administration	**438**	**564**	**55**	**1,057**
Depreciation and amortization	**240**	**287**	**10**	**537**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**469**	**357**	**(2)**	**824**
Financing charges				**308**
Income before provision for payments in lieu of corporate income taxes				**516**
Capital expenditures	**918**	**643**	**5**	**1,566**
2008				
Segment profit				
Revenues	1,212	3,334	51	4,597
Purchased power	–	2,181	–	2,181
Operation, maintenance and administration	387	531	47	965
Depreciation and amortization	254	287	7	548
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	571	335	(3)	903
Financing charges				292
Income before provision for payments in lieu of corporate income taxes				611
Capital expenditures	704	570	10	1,284

December 31 (Canadian dollars in millions)	2009	2008
Total assets		
Transmission	**9,118**	7,877
Distribution	**6,531**	5,873
Other	**161**	128
	15,810	13,878

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

20. Subsequent Events

On January 22, 2010, Hydro One issued $500 million in notes under the Company's MTN Program. The issue was an additional offering of 3.13% notes maturing on November 19, 2014, originally issued on November 19, 2009. The total amount outstanding for this issue is now $750 million.

On January 22, 2010, Hydro One entered into two $250 million notional principal amount fixed-to-floating interest rate swaps to convert $500 million of Hydro One's 3.13% coupon note maturing November 19, 2014, into three-month variable rate debt.

On January 22, 2010, Hydro One purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement its bank credit facilities.

On February 2, 2010, Hydro One entered into an additional $500 million committed revolving credit facility which supports its Commercial Paper Program and matures February 2013.

On February 3, 2010, Hydro One reduced its $1,000 million committed revolving credit facility maturing on August 20, 2010 by $250 million, to $750 million.

21. Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2009 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	2007	2006	2005
Statement of operations data					
Revenues					
Transmission	**1,147**	1,212	1,242	1,245	1,310
Distribution	**3,534**	3,334	3,382	3,273	3,085
Other	**63**	51	31	27	21
	4,744	4,597	4,655	4,545	4,416
Costs					
Purchased power	**2,326**	2,181	2,240	2,221	2,131
Operation, maintenance and administration	**1,057**	965	995	880	792
Depreciation and amortization	**537**	548	521	515	487
	3,920	3,694	3,756	3,616	3,410
Regulatory recovery[1]	**–**	–	–	–	91
Income before financing charges and provision for payments in lieu of corporate income taxes	**824**	903	899	929	1,006
Financing charges	**308**	292	295	295	325
Income before provision for payments in lieu of corporate income taxes	**516**	611	604	634	681
Provision for payments in lieu of corporate income taxes	**46**	113	205	179	198
Net income	**470**	498	399	455	483
Basic and fully diluted earnings per common share *(Canadian dollars)*	**4,528**	4,797	3,809	4,366	4,652

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**9,118**	7,877	7,273	6,950	6,813
Distribution	**6,531**	5,873	5,407	5,161	4,893
Other	**161**	128	106	99	92
Total assets	**15,810**	13,878	12,786	12,210	11,798
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,655**	1,300	1,452	1,194	1,341
Long-term debt	**6,281**	5,733	5,063	4,848	4,443
Other long-term liabilities	**2,456**	1,721	1,385	1,347	1,298
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,791**	1,497	1,258	1,184	1,079
Accumulated other comprehensive income	**(10)**	(10)	(9)	–	–
Total liabilities and shareholder's equity	**15,810**	13,878	12,786	12,210	11,798

[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.

Five-Year Summary of Financial and Operating Statistics *(continued)*

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	2007	2006	2005
Other financial data					
Capital expenditures					
Transmission	**918**	704	560	402	349
Distribution	**643**	570	511	417	338
Other	**5**	10	20	4	4
Total capital expenditures	**1,566**	1,284	1,091	823	691
Ratios					
Net asset coverage on long-term debt[2]	**1.79**	1.84	1.87	1.92	1.93
Earnings coverage ratio[3]	**2.15**	2.63	2.67	2.67	2.69
Operating statistics					
Transmission					
Units transmitted *(TWh)*[4]	**139.2**	148.7	152.2	151.1	157.0
Ontario 20-minute system peak demand *(MW)*[4]	**24,477**	24,231	25,809	27,056	26,219
Ontario 60-minute system peak demand *(MW)*[4]	**24,380**	24,195	25,737	27,005	26,160
Total transmission lines *(circuit-kilometres)*	**28,924**	29,039	28,915	28,600	28,547
Distribution					
Units distributed to Hydro One customers *(TWh)*[4]	**28.9**	29.9	30.2	29.0	29.7
Units distributed through Hydro One lines *(TWh)*[4, 5]	**43.5**	44.7	45.7	44.7	45.6
Total distribution lines *(circuit-kilometres)*	**123,528**	123,260	122,933	122,460	122,118
Customers	**1,333,920**	1,325,745	1,311,714	1,293,396	1,273,768
Total regular employees	**5,427**	5,032	4,602	4,295	4,189

[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, 2009)*

James Arnett[1,2,5]
Chair of the Board of Directors, Hydro One Inc.

Sami Bébawi[2,5,6]
Advisor to the President, SNC-Lavalin Group Inc.

President, Geracon Inc.

Kathryn A. Bouey[3,4,6]
President, TBG Strategic Services Inc.

Corporate Director

Laura Formusa
President and Chief Executive Officer, Hydro One Inc.

Don MacKinnon[5,6]
President, Power Workers' Union

Michael J. Mueller[1,2,4]
Corporate Director

Walter Murray[1,3,4]
Corporate Director

Robert L. Pace[1,3]
President and CEO, The Pace Group Ltd.

Gale Rubenstein[2,5]
Partner, Goodmans LLP

Douglas E. Speers[3,4,6]
Corporate Director

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 eight times in 2009.

[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 seven times in 2009.

[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 seven times in 2009.

[4] *Business Transformation 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 and Smart Grid & Continuous Innovation Strategy. The committee met four times in 2009.

[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 and reviews the Company's proposals for rate applications, compliance actions and reports. The committee met five times in 2009.

[6] *Health and Safety Committee* The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs and compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2009.

Corporate Information

Corporate Address
483 Bay Street
Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations
(416) 345-6867
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 and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP

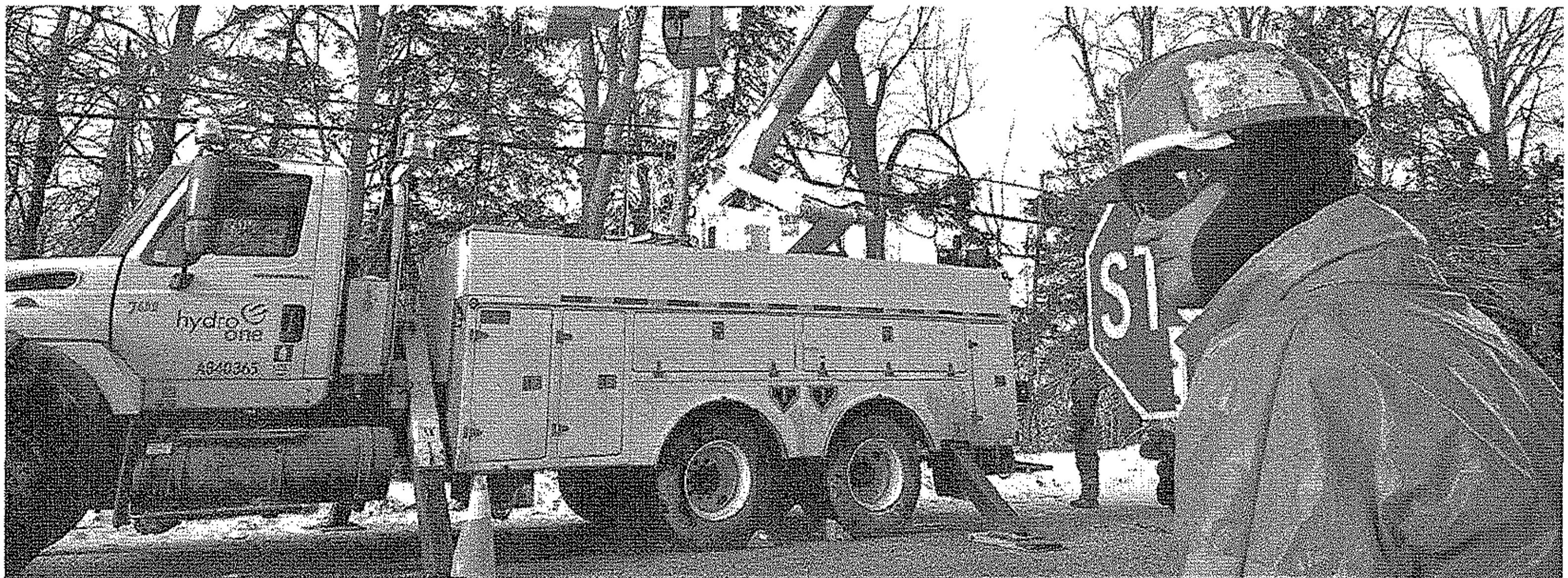
Concept and Design: THE WORKS www.worksdesign.com

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit **www.HydroOne.com**.

TRANSFORMINGENERGY

2010 ANNUAL REPORT

hydroOne



Reliable. Productive. Sustainable.

Every hour of every day, Hydro One works to ensure Ontario has a safe, reliable and cost-effective electricity system. It takes time to build a system like ours. We make prudent and logical investments and we build our system to last.

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 21 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. This business represents less than 1 per cent of our total assets.

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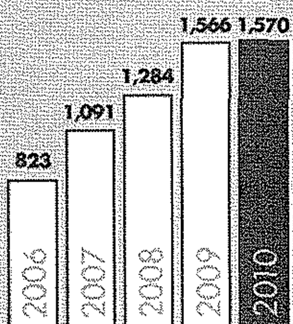
CONSOLIDATED FINANCIAL
HIGHLIGHTS AND STATISTICS

Capital Expenditures

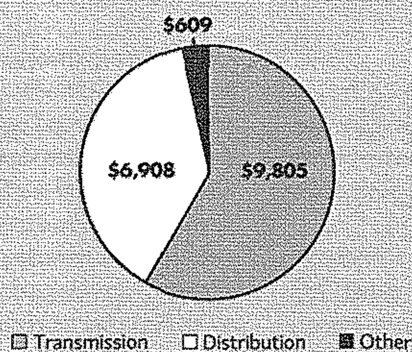
(Canadian dollars in millions)



Total Assets

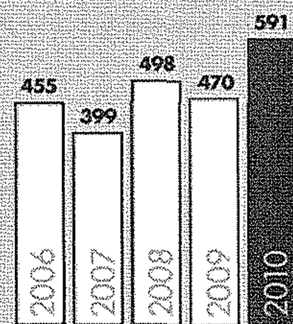
December 31, 2010

(Canadian dollars in millions)



Net Income

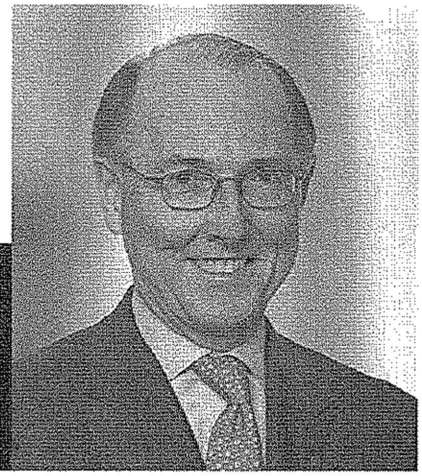
(Canadian dollars in millions)



Year ended December 31 *(Canadian dollars in millions)*	**2010**	2009	$ Change	% Change
Revenues	**5,124**	4,744	380	8
Purchased power	**2,474**	2,326	148	6
Operating costs	**1,661**	1,594	67	4
Net income	**591**	470	121	26
Net cash from operations	**1,164**	892	272	30
Average Ontario 60-minute peak demand (MW)[1]	**21,572**	20,798	774	4
Distribution – units distributed to customers (TWh)[1]	**29.1**	28.9	0.2	1

[1] System-related statistics include preliminary figures for December.

LETTER FROM THE CHAIR



Our electricity system continued to perform reliably, safely and effectively this past year, at a time of investing heavily to maintain and upgrade aging infrastructure and to accommodate the various demands of the Green Energy Act and of the Province's Long-Term Energy Plan to encourage renewable energy generation.

Hydro One's core mandate is the safe, reliable and cost-effective transmission and distribution of electricity to Ontario homes and businesses. In carrying out that mandate, Hydro One has a second mandate to operate as a commercial enterprise.

The Board of Directors is responsible for overseeing the management of the business and affairs of Hydro One and, as such, for overseeing the implementation of both mandates. In doing so, the Board has a general fiduciary responsibility and duty of care to act in the best interest of Hydro One. The Board has a more specific responsibility to act pursuant to the terms of our existing Memorandum of Agreement with the Province of Ontario – respecting mandate, governance, responsibilities, performance expectations and executive compensation.

I believe the Board performed very well in 2010 in accordance with such oversight responsibilities.

Our electricity system continued to perform reliably, safely and effectively this past year, at a time of investing heavily to maintain and upgrade aging infrastructure and to accommodate the various demands of the Green Energy Act and of the Province's Long-Term Energy Plan to encourage renewable energy generation.

These investments have had significant rate ramifications. The Board is very aware of, and sensitive to, the impact of rate increases on our customers, and we will continue to seek productivity improvements to mitigate the costs of these heavy investments.

At the same time, we delivered increased value to our shareholder. We maintained our long-term "A" credit rating, which enabled us to continue to borrow on advantageous terms, thus mitigating the costs of our work plan.

A major oversight tool for the Board is the Corporate Scorecard, which measures management's performance in accordance with and against the approved Strategic Plan and annual Business Plan. I am pleased to report that, for 2010, the goals of the Corporate Scorecard were met on balance. While management compensation was frozen pursuant to the *Restraint Act*, appropriate short-term incentive compensation was paid to management in accordance with our existing plan as permitted by the *Restraint Act*.

The Board approved a significant senior management reorganization, which we believe will enhance the performance of the organization. We also approved the creation of a new pension-investment function and the creation of a new position of Chief Investment and Pension Officer, which should improve performance of the pension fund over the longer term.

I want to thank all our employees, and my colleagues on the Board of Directors, for their commitment to Hydro One and its various stakeholders.

James Arnett

James Arnett
Chair of the Board of Directors
Hydro One Inc.

LETTER FROM THE PRESIDENT AND CEO

It is critical that we maintain an effective balance between our customers' needs and the urgent need to sustain our critical transmission and distribution assets and connect new sources of renewable energy.

2010 was a year of solid progress on many fronts. We are confident in our ability to achieve our longer-term mission and vision, which will enable us to continue serving our customers safely, reliably and cost-effectively.

We are investing in Ontario's energy future. Our focus is on prudently maintaining and expanding our distribution and transmission systems while moving to adopt the technologies that will improve our value to our customers and our shareholder. It is critical that we maintain an effective balance between our customers' needs and the urgent need to sustain our critical transmission and distribution assets and connect new sources of renewable energy.

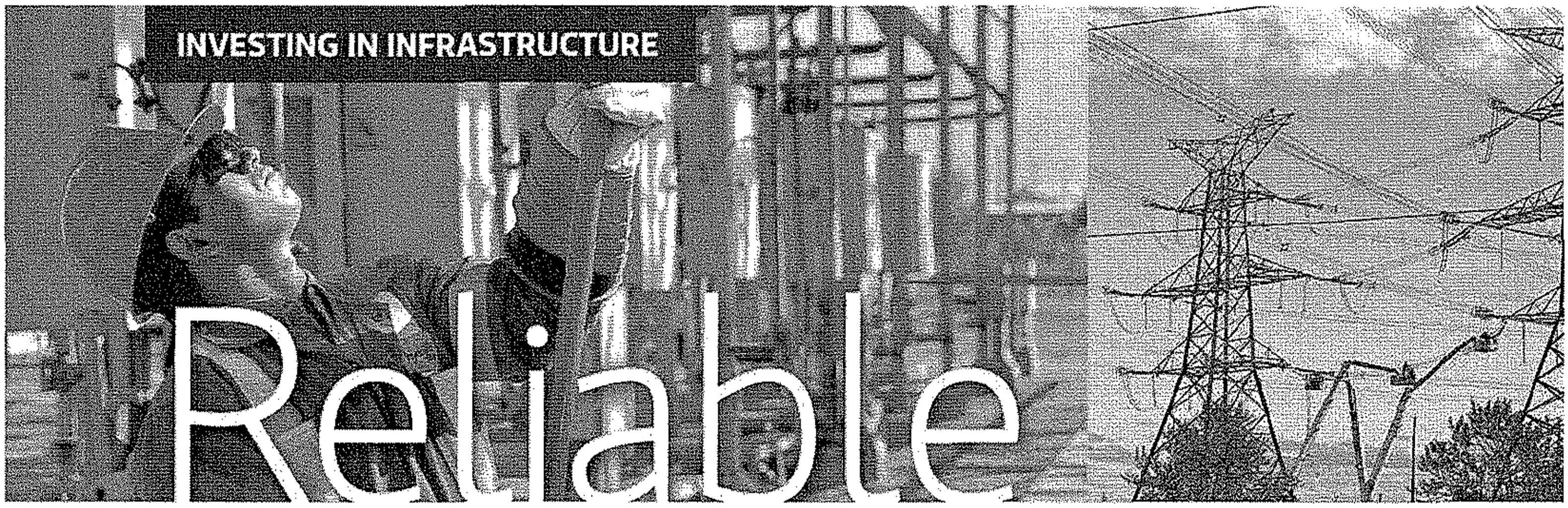
We know that meeting the expectations of the people of Ontario is a demanding task as our sector goes through a dynamic period of growth and change. We are listening to our customers and renewing our electricity system to enable clean and renewable sources of electricity. As we make prudent and efficient investments in Ontario's electricity grid, I am confident that Hydro One will continue to deliver on our promise of value in many different ways in the years ahead.

We will continue to operate a safe and reliable system and look for increased efficiencies while building the system of tomorrow. Our customers deserve value for the price of the services they pay for and we remain committed to providing that value and to improving our customers' satisfaction with Hydro One. We will also continue to improve the sustainability of our operations and enhance our customers' ability to manage their energy costs and efficiency.

As always, our focus must be on the safety of our employees. Our Journey to Zero program will enable us to fulfill our commitment to our co-workers and their families to be safe in our work. We must be relentless in our pursuit of this goal.

I'd like to thank the employees of Hydro One for their dedication and hard work as the industry continues to change and transform. Together, we are industry leaders in developing the Smart Grid, we are facilitators in connecting renewable energy and we are a financially responsible Company providing value to our customers and the Province of Ontario.

Laura Formusa
President and CEO, Hydro One Inc.



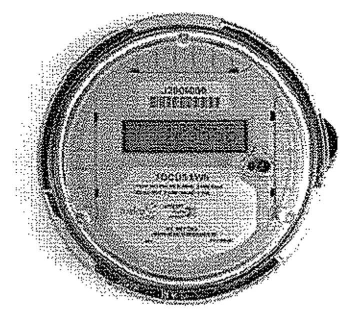
Improvements to system reliability
Improving the reliability of Ontario's electricity system means knowing when and where to make upgrades and repairs. By using analytical information like outage occurrences and inspection results, we ensure that the most important upgrades are done first.

In 2010, we invested $1.57 billion in capital expenditures to improve system reliability and performance, address an aging power system, facilitate the connection of new generation and improve service to our customers.

Long-term initiatives like the 500-kV transmission line unbundling project from Cherrywood TS to Claireville TS provide operational and maintenance flexibility.

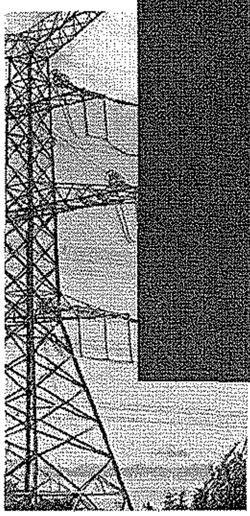
Work on the Bruce to Milton Transmission Reinforcement Project moved ahead on schedule with tower construction underway on segments of the line where approvals have been obtained and land rights have been acquired. The project is expected to be in service by late 2012 and will deliver approximately 3,200 MW of new, renewable and nuclear power from the Huron-Grey-Bruce area.

$1.57 billion invested in improving our system.



Smart meter, smart grid
Ontario's electricity grid is getting smarter. We completed the installation of more than 1.3 million smart meters of which more than 1.1 million are enabled to support Time-of-Use pricing. This is one of the largest deployments of smart meters undertaken by any utility in North America. We converted more than 553,000 customers to Time-of-Use pricing, exceeding the Ontario Energy Board's monthly cumulative Time-of-Use target.

1.3 million smart meters installed across the Province.

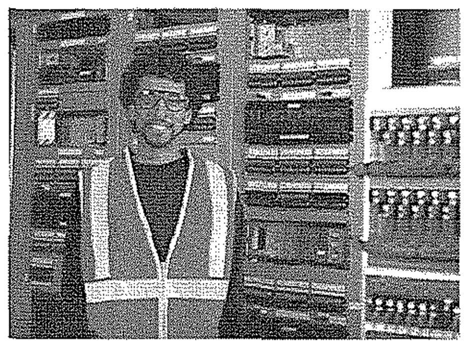


HYDRO ONE CONTINUES TO MAINTAIN AND EXPAND OUR DISTRIBUTION AND TRANSMISSION SYSTEMS WHILE ENSURING THE RELIABLE DELIVERY OF POWER TO THE PROVINCE OF ONTARIO AND OUR CUSTOMERS.

The Long-Term Energy Plan is pointing our industry in an exciting new direction. It maps out an integrated approach to the development of Ontario's electricity system and enables renewable technology.

On the cutting edge of innovation

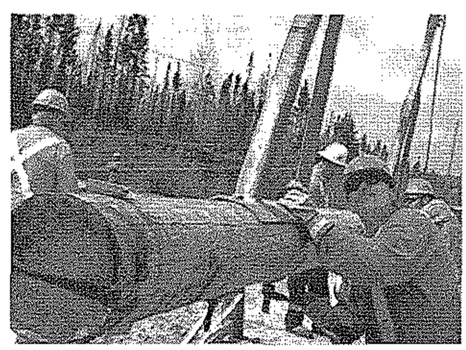
Innovation is playing a key role in the future of Ontario's electricity system. Hydro One has partnered with Ryerson University to establish the Centre for Urban Energy, which will research innovative and practical solutions to urban energy issues. This partnership will help Hydro One identify solutions for integrating new technologies and develop the future leaders of the energy sector.



Hydro One has also partnered with the University of Western Ontario and the University of Waterloo to promote the development of innovative electrical engineering solutions to connect clean and renewable energy. These partnerships also include funding student scholarships and awards.

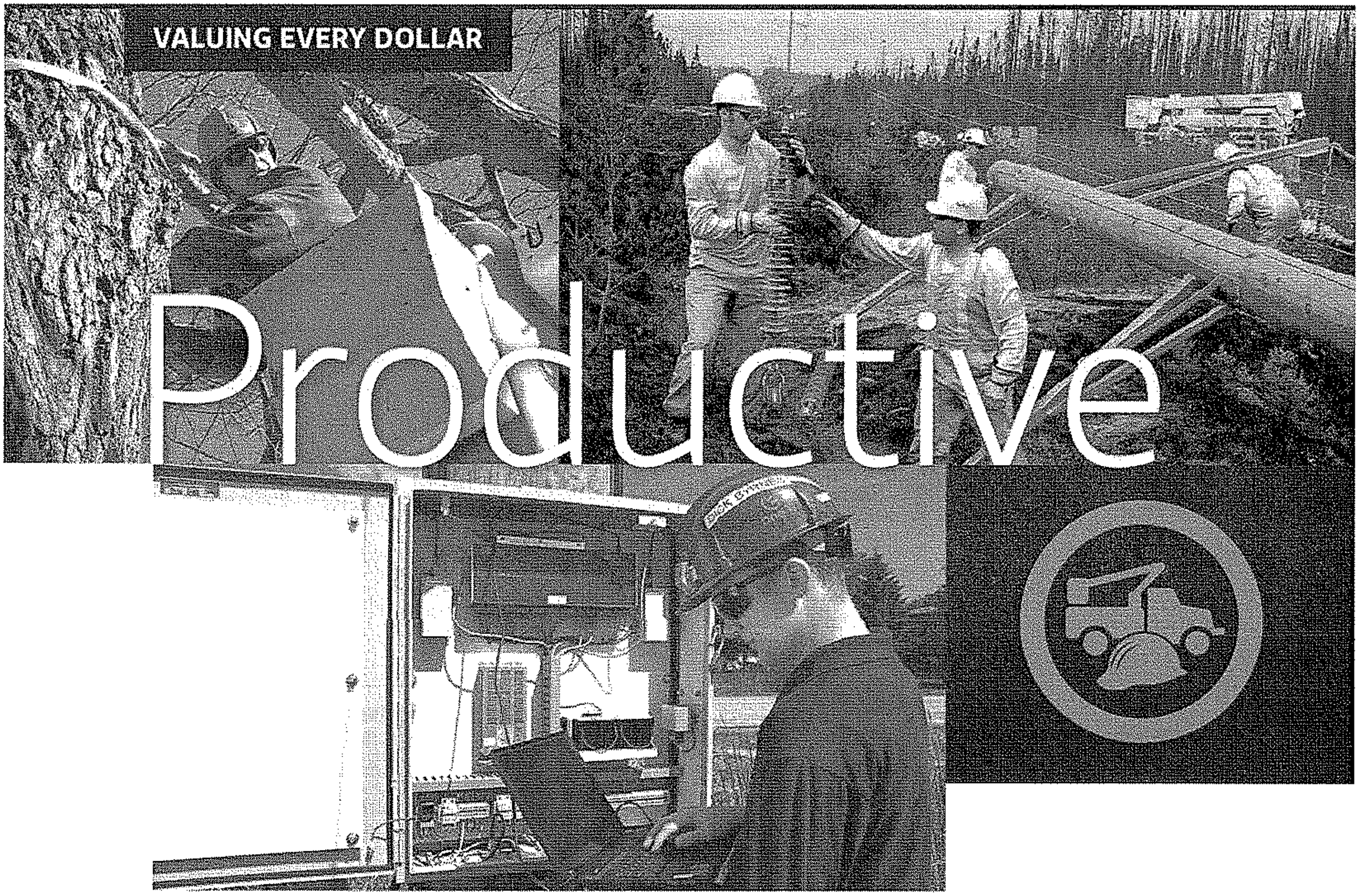
We are there when our customers need us

In 2010, high winds, snow, forest fires and tornadoes caused numerous outages across the Province. But customers can count on our highly-trained staff to respond rapidly and communities can depend on our mobile response efforts, which see crews from unaffected areas arriving to help get the power back on quickly. For example, when Chapleau lost power due to a forest fire, Hydro One crews travelled from across Ontario to rebuild 15 single and twin pole structures as soon as the fire was under control.



VALUING EVERY DOLLAR

Productive



Strong financial performance

Total revenues for 2010 were $5,124 million, an increase of $380 million from 2009. Transmission revenues of $1,307 million and distribution revenues of $3,754 million reflected various rate increases in support of necessary work program requirements and the impact of higher temperatures experienced this summer.

We also maintained an "A" credit rating, which means the Company is able to access the long-term debt markets at a reasonable cost. This is critical to completing our work programs cost-effectively. During the year, we successfully issued $1.5 billion of debt financing through our Medium-Term Note Program.

> For more than a century, the electricity sector in Ontario has delivered a safe, reliable and cost-effective supply of electricity.

Cost-cutting measures

As Ontario's largest electricity transmission and distribution company, Hydro One must find ways to balance sustainment of assets and affordability of electricity. Employees across the Company are helping to find ways to reduce costs and improve productivity.

Some areas which Hydro One has improved productivity and provided value to customers include:

- $34 million in savings in 2010 by moving to standardized planning and reporting.
- Automated meter reading associated with smart meters is expected to reduce costs by taking meter reads and detecting meter issues remotely rather than dispatching staff.

PROVIDING VALUE TO OUR CUSTOMERS MEANS ENSURING EVERY DOLLAR SPENT IS A DOLLAR SPENT WISELY. HYDRO ONE IS FINDING WAYS TO INCREASE PRODUCTIVITY AND BE TRANSPARENT AND ACCOUNTABLE TO ALL ONTARIANS.

Measuring productivity

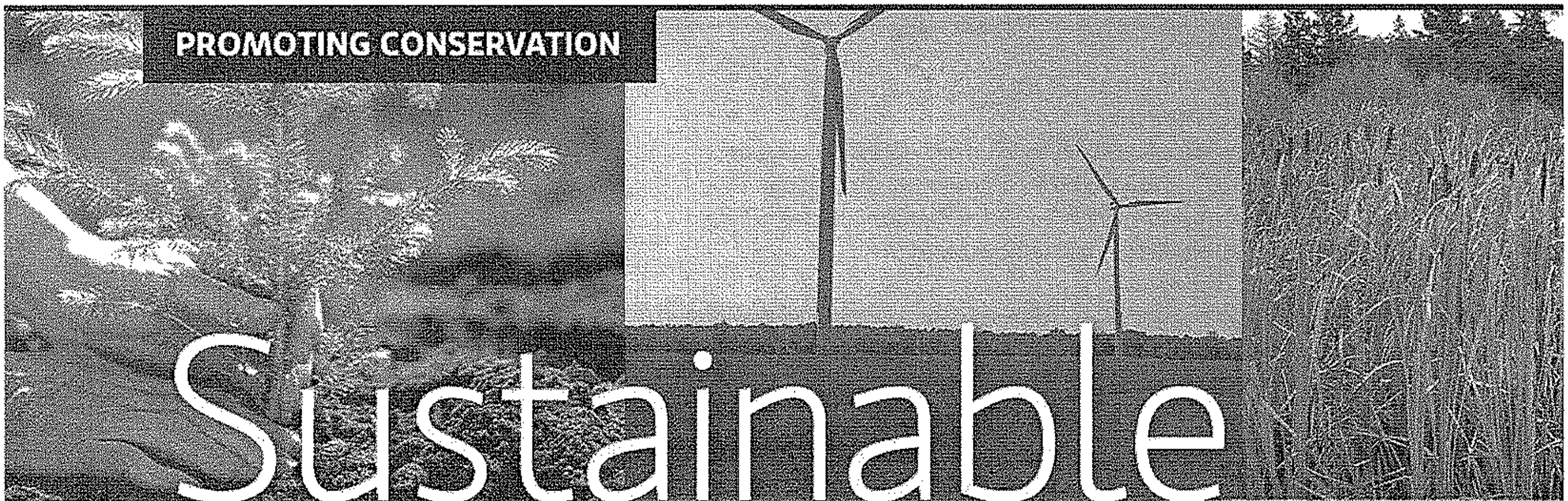
In 2009, we introduced two rigorous new performance metrics: Cost per Asset Value for transmission and Cost per Line Length for distribution. We met both targets in 2010 with a transmission unit cost of 4.6 per cent per transmission asset and a distribution unit cost of $6,600 per kilometre of line. We will continue to measure and benchmark productivity every year, with the goal of placing in the top quartile when measured against comparable North American utilities.

Connecting renewable energy

Connecting solar, wind, hydro-electric and biomass generation to the electricity grid allows the Province to replace coal generation with clean power. Hydro One plays an important role in the connection of renewable energy projects under the Feed-In Tariff (FIT) and Micro Feed-In Tariff (microFIT) programs. In 2010, we connected 2,397 microFIT projects. In addition, since 2003, we have connected more than 2,000 megawatts of renewable generation and more than 4,500 megawatts of natural gas generation. That's enough to power 42,000 homes for a year.

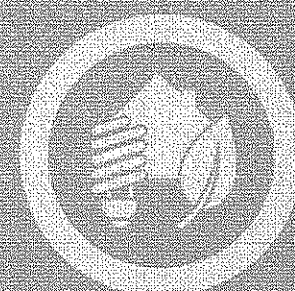
We connected 2,397 microFIT projects to our system in 2010.

PROMOTING CONSERVATION



Sustainable

AS PARTNERS IN POWERFUL COMMUNITIES ACROSS ONTARIO, HYDRO ONE PROMOTES SUSTAINABLE DECISION MAKING. BY MAKING GREENER CHOICES, OUR EMPLOYEES AND OUR CUSTOMERS ARE REDUCING THEIR IMPACT ON THE ENVIRONMENT.



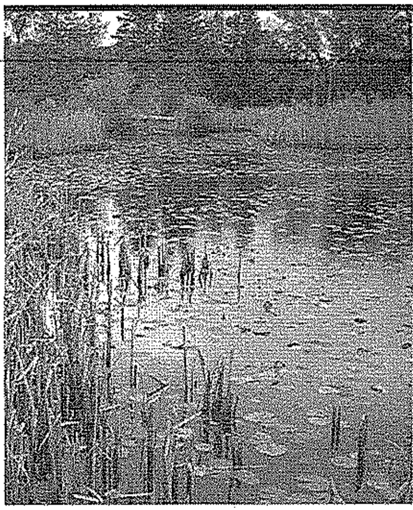
Making Greener Choices

Greener Choices, a grassroots employee-run environmental group in the Company, was established in 2008 to reduce greenhouse gases produced by Hydro One. It focuses on three areas, fleet, facilities and employees. In 2010, retrofits were conducted at the Central Maintenance System facility that reduced energy consumption by 280,000 kWh through lighting upgrades. Greener Choices is also taking aim at Hydro One's fleet, getting hybrids on the road and retiring vehicles that are no longer needed. Through these efforts and others, the Greener Choices program prevented the release of 2,595 tonnes of CO_2 into the atmosphere in 2010. That's like taking more than 500 cars off the road.

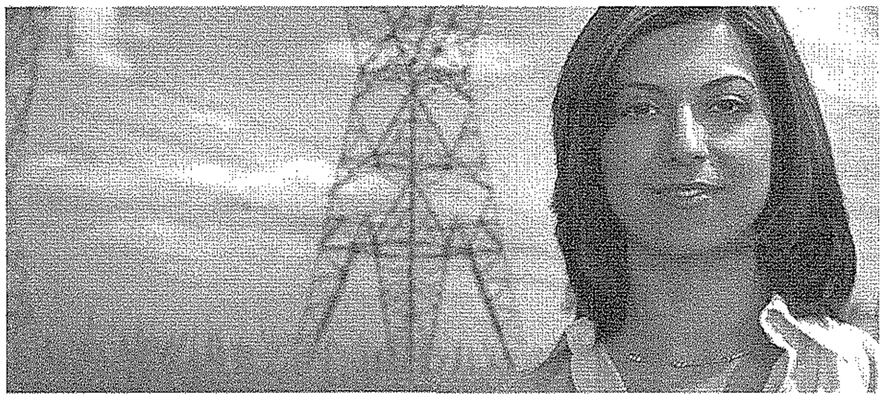
Release of 2,595 tonnes of CO_2 prevented by Greener Choices initiatives.

Sustainability Company of the Year

The Canadian Electricity Association named Hydro One the Sustainability Company of the Year. This honour is in recognition of our ongoing efforts to reduce environmental impacts in all aspects of our operations, including fleet and facilities, through our conservation and demand management programs and through our support for biodiversity projects in local communities.



Hydro One has a strong and positive corporate giving culture. Our employees give generously to our charity campaign, volunteer their time in their local communities and are taking steps to reduce their environmental impact.



Hydro One received the Canadian Electricity Association annual Environmental Commitment Award for our Biodiversity Initiative for the Bruce to Milton Transmission Reinforcement Project. This project will create and enhance natural habitats in the communities touched by the project. We are working on this in partnership with First Nations and Métis communities and community-based agencies and stakeholders.

Customer conservation and demand management programs

Hydro One is helping to build a conservation culture within Ontario and our customers are leading the way. By retiring inefficient fridges and freezers and making energy retrofits to their homes, 1.5 million customers have helped save 500 million kWh of electricity since 2005. That's enough to power approximately 42,000 homes for a year, resulting in reductions in greenhouse gas emissions savings of more than 86,000 tonnes of CO_2.

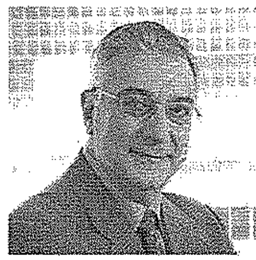
Journey to Zero

Achieving an injury-free workplace starts with each and every employee. That's why the Journey to Zero program was launched in 2009, aimed at identifying opportunities to improve Hydro One's health and safety performance. In 2010, we had a frequency of 2.8 medical attentions and 0.05 lost-time injuries per 200,000 hours worked. This exceeded our target of 3.6 medical attentions and 0.23 lost-time injuries per 200,000 hours worked.

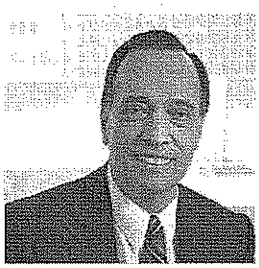
Our customers helped reduce demand for electricity by **500 million kWh.**

HYDRO ONE
SENIOR MANAGEMENT

Laura Formusa
President and Chief Executive Officer, Hydro One Inc.

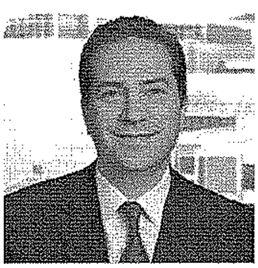


Joe Agostino
General Counsel

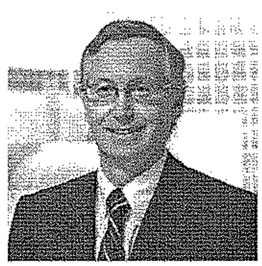


John Fraser
Senior Vice-President, Internal Audit and Chief Risk Officer

Peter Gregg
Executive Vice-President, Operations



Carmine Marcello
Executive Vice-President, Strategy



Sandy Struthers
Executive Vice-President and Chief Financial Officer

MANAGEMENT'S
DISCUSSION AND ANALYSIS

We prepare our financial statements in Canadian dollars 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, 2010 and 2009.

EXECUTIVE SUMMARY

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). Our mission and vision have been refined to recognize the unique role we play in the economy of the province and as a provider of critical infrastructure to all our customers. We will be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety, stewardship, excellence and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial and transparent and values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2010, we continued to focus on our core businesses, substantially maintained and improved our performance in various key areas of the Company, and made important contributions to the rebuilding of Ontario's core infrastructure while preparing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following governance structure:

Core Business and Strategy → **Key Performance Drivers** → **Capability to Deliver Results** → **Results and Outlook**

Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed on page 4, encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

Key Performance Drivers

We have identified performance drivers critical to achieving our strategic goals. Each driver is specific to measuring our success in achieving a specific goal. We establish specific performance targets against each driver every year aimed at achieving our strategic goals over time. For example, we calculate lost-time injury frequencies and medical attentions to measure our progress toward an injury-free workplace and the duration and frequency of unplanned interruptions to measure the success of our initiatives to increase the reliability of our transmission and distribution systems. Reduced carbon emissions demonstrate our commitment to protecting the environment. These and other key performance drivers are included in our discussion of our performance measures beginning on page 5.

Capability to Deliver Results

We continued to use a balanced scorecard approach and set 18 stretch targets for 2010 as we strive to manage our key performance drivers and deliver results each and every year. This year we met or exceeded 14 of 18 targets, representing an improvement over last year when we met or exceeded 8 of 13 stretch targets. We are on target to enable clean and renewable energy in Ontario with the implementation of our Bruce to Milton Project that will create Ontario's new clean energy corridor.

We continue to prioritize safety in the workplace, adding a new performance measure this year. We exceeded our target for lost-time injuries by 78% and exceeded our new target for medical attentions by 22%. We are focused on balancing customer needs in the changing electricity sector and achieved an overall satisfaction score of 89% for both our transmission and distribution customers. The results of our efforts are fully discussed in the section Performance Measures and Targets, beginning on page 5. Our capability to deliver results in each of our strategic areas is limited by risks inherent in the regulatory environment, our business, our workforce and the economic environment. These risks, as well as our strategies to mitigate them, are discussed beginning on page 25.

Results and Outlook

During 2010, our financial fundamentals remained strong, with current year net income of $591 million. Our OEB-approved revenue requirements for our Transmission and Distribution Businesses for 2010 were $1,257 million and $1,146 million, respectively. The approved rates support our work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We maintained "A" category credit ratings and successfully issued $1,500 million in debt financing, while repaying $600 million of debt maturing in the year. A full discussion of our results of operations and financing activities can be found beginning on pages 14 and 18, respectively.

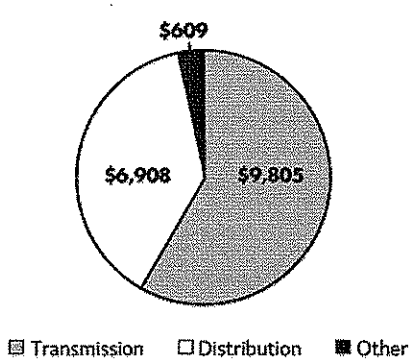
In 2010, we invested more than $1.5 billion in capital expenditures to improve system reliability and performance, address an aging power system, facilitate new generation and improve service to customers. Our estimated future capital expenditures for 2011 and 2012 have decreased marginally from those previously disclosed as a result of various letters received from the Minister of Energy, the introduction of a Long-Term Energy Plan (LTEP) and an OEB policy to further competition for transmission development. Similarly, we eliminated requirements for Green Transmission projects for new lines from our budgeted expenditures and refined our requirements to support distributed generation. The impacts were partially offset by requirements associated with our existing grid. We continue to focus on addressing aging infrastructure, including critical stations that serve industry and major customer load areas. Our future capital expenditures are more fully discussed beginning on page 21.

OVERVIEW

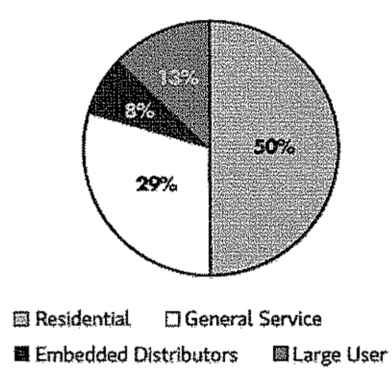
Transmission

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 our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2010, we earned total transmission revenues of $1,307 million primarily by transmitting approximately 142 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 4,600 MW and exports of approximately 6,000 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, 2010 (CAD $ millions)



2010 Distribution Revenues



Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.3 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 412 large user 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. We earned total distribution revenues in 2010 of $3,754 million. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers. In terms of assets, our Distribution Business represents approximately 40% of our total assets.

Other

Our other business segment contributed revenues of $63 million in 2010 and has assets of about $609 million, which constitute 3% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Health and safety: Nothing is more important than the health and safety of our employees and those who work on our property, as well as maintaining a safe environment for the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality service.

Stewardship: We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.

Innovation: We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that do not stand alone and are inextricably linked with one another. They drive the fulfillment of our mission and vision.

Creating an injury-free workplace and maintaining public safety. Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will continue to reinforce that nothing is more important than the health and safety of our employees.

Satisfying our customers. We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image.

Continuous innovation. Innovation is critical to achieving our mission and vision and represents one of our core values. Over the next two decades, we will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs.

Building and maintaining reliable, cost-effective power delivery systems. Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on incorporating smart grid technology, providing reliable service over a diverse geography, supporting the connection of renewable generation, seeking efficiencies through productivity initiatives and remaining open to opportunities to rationalize the distribution sector.

Protecting and sustaining the environment. Consistent with our value of stewardship, Hydro One plays a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.

Employee engagement. We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. Our labour strategy will enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintenance of a commercial culture that increases value for our shareholder. We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity.

Productivity improvement and cost-effectiveness. To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of the Ontario economy and its residents.

Performance Measures and Targets

We measure and target our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we achieve our strategic objectives. In 2010, we met or exceeded 14 of 18 stretch targets. Overall, we are making progress towards achieving our strategic goals.

Creating an injury-free workplace and maintaining public safety

The potentially hazardous nature of our business requires a continuous focus on safety. Our people underpin everything we do, and as a result, safety is paramount. Our efforts to achieve an injury-free workplace are measured by our lost-time injury frequency and our newly added reportable medical attentions frequency. Overall, we exceeded our challenging 2010 target of 0.23 lost-time injuries per 200,000 hours worked, which is also a considerable improvement over our 2009 results. We also exceeded our 2010 target of 3.6 medical attentions per 200,000 hours worked. Medical attentions are incidents reported to the Workplace Safety and Insurance Board that are more serious than basic first aid. While we monitor both of these measures to identify possible situations that may increase the risk of injury, medical attentions are considered a leading indicator. These injuries range from physical strains to those caused by electrical contacts. We continuously emphasize the improvement of safety performance and strive to achieve zero lost-time injuries by ensuring that all staff are appropriately trained and equipped for the hazards they may face. This involves continued coaching and mentoring, and building on our learning and experience.

At the end of 2009, we launched our Journey to Zero initiative aimed at identifying key opportunities for improvement in our health and safety system in order to achieve world-class health and safety performance. During 2010 we formed a steering committee for this initiative, held workshops to prioritize the opportunities identified at the end of last year and developed an action plan to address the top areas for improvement. In October 2010, we were pleased to be informed by the Workplace Safety and Insurance Board that we had passed our Workwell audit, a comprehensive independent review of all aspects of our workplace health and safety program including policies, standards, training, records, performance and employee representation.

We continue to promote public safety and the safe use of electricity through public service announcements and education programs in schools to teach children how to stay safe. We also continue to work with law enforcement agencies to combat copper theft, which endangers our employees and the public.

Satisfying our customers

Customer satisfaction is vital to our success. This is measured by a combination of independent surveys and transactional measures conducted for each of our customer segments. In 2010, the overall satisfaction level for both our distribution and transmission customers exceeded our targets. For our Distribution Business, overall customer satisfaction survey results of 89% exceeded our target of 81%. While we achieved consistent results compared to the prior year within our large distribution customer and residential and small business customer segments, we significantly increased customer satisfaction among distribution-connected generators. Satisfaction in this group was impacted by addressing concerns from last year's surveys, clarifying processes and enhancing communications with customers. Connection application volumes are increasing and we remain focused on managing customer expectations.

For our transmission customers, we experienced slightly lower results for our LDC customers than planned and are assessing the results to improve processes next year. However, our overall transmission customer survey results were offset by a significant improvement in our transmission-connected generator customer satisfaction as a result of addressing concerns noted in last year's surveys. We continue to strive for customer service excellence. We continue to make our customers a high priority, and implement targeted strategies designed to meet the unique needs of each customer segment and address their concerns through a range of initiatives to improve customer satisfaction levels.

Continuous innovation

We are committed to identifying and providing innovative solutions that will improve the reliability and efficiency of electricity delivery and provide our customers with more capability to manage their power consumption. Among our continuous innovation initiatives in 2010, smart meters remained a priority. We have more than 1,314,000 smart meters installed to date, of which approximately 1,140,000 meters are enabled to support time-of-use billing. This represents a significant step forward in supporting the Smart Grid initiative. We fell short of our target of 1,170,000 meters enabled to support time-of-use billing due to challenges encountered related to the communications network needed to address the diverse needs of the geography across the province. We continue to anticipate that our OEB commitments will be met in 2011.

A new measure for continuous innovation this year monitors green grid initiatives, which are an integral part of the GEA. These initiatives include establishing a communications network in the Greater Owen Sound area to test business applications for a smart electricity grid, developing a business case for further deployment of the communications network to the province, and developing utility solutions for the current challenges around installing and operating large numbers of distributed generation on our distribution system. We successfully achieved all 12 milestones related to these initiatives.

Building and maintaining reliable, cost-effective power delivery systems

As stewards of the province's electricity grid, we aim to maintain and build trust in our operations. In 2010, 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. In addition, our aim is to meet the growing demand for renewable generation. The reliability of our transmission and distribution systems is measured by the duration of unplanned customer interruptions throughout the year and our transmission system is further measured by the frequency of unplanned customer interruptions. In 2010, our transmission system met our reliability targets for both frequency and duration of interruptions. The transmission frequency of customer unplanned interruptions met the target for the year. The transmission duration of unplanned customer interruptions was 9.1 minutes, significantly exceeding the target of 16.0 minutes, and significantly improved from 19.7 minutes in 2009.

Due to a number of challenges experienced in the last quarter of the year, the reliability of our distribution system was impacted in terms of duration of interruptions. Two severe winter storms affected the reliability of our distribution system. The duration of interruptions for our distribution customers was 7.1 hours, or 0.2 hours higher than target and 0.1 hours higher than last year. We are conscious that residential customers and businesses of all sizes require reliable service, and consequently, we will continue to strive to improve the reliability of both our transmission and distribution systems.

Protecting and sustaining the environment

As stewards of significant electricity assets, we have implemented a number of environmental initiatives aimed at instilling environmental awareness and action within our corporate culture. In 2010, we assessed two key metrics related to the Bruce to Milton Project and greenhouse gas reductions. We met our milestone targets related to the Bruce to Milton Project, which will create Ontario's new clean energy corridor. Successful completion of the Bruce to Milton Project will increase transmission capability to deliver 1,700 MW of renewable generation identified in the area, as well as about 1,500 MW of power from the refurbished units at the Bruce Power Facility. On December 16, 2009, we received conditional Environmental Assessment approval for the project. Preparation of this environmental assessment involved three years of technical and environmental field work, and extensive consultation with land owners, interest groups, elected officials and First Nations and Métis communities. This year, we were recognized by the CEA, receiving an Environmental Commitment Award for our extensive Biodiversity Initiative related to the Bruce to Milton Project. This initiative goes beyond our traditional approach to biodiversity, using innovative ways of mitigating the effects of woodlot clearing. Our Biodiversity Initiative will develop and support a number of stewardship and biodiversity opportunities such as replanting grasslands, removal of invasive species and restoring forests in the communities affected by the Bruce to Milton Project. We are funding 23 locally-designed biodiversity projects located on public lands within the four watersheds the Bruce to Milton Project crosses. These projects will help to ensure environmental sustainability and will maintain and enhance the natural habitat. This initiative is being undertaken in collaboration with First Nations and Métis communities and community-based stakeholders and agencies.

We take our responsibility to reduce our carbon footprint very seriously. We did not meet our overall greenhouse gas reduction target as a result of not being able to verify our specific target to reduce sulphur hexafluoride emissions. However, we did exceed the target for the reduction of greenhouse gas emissions from other programs. In 2010, we removed approximately 2,595 metric tonnes of greenhouse gases from the environment, exceeding our target of 1,250 metric tonnes from these other initiatives that were aimed at improved deliveries of bio-diesel fuel at Hydro One Remotes, better efficiency of fleet utilization, including our Tire Smart Program, the purchase of fuel-efficient and hybrid vehicles and green initiatives at our facilities. Our continued commitment to the people of Ontario has been recognized again this year by Corporate Knights Inc., an independent company focused on promoting and reinforcing sustainable development in Canada. We were named one of the top five Corporate Citizens in Canada, our third top-ten ranking in three years.

We have a publicly available environmental policy and are committed to protecting the environment for current and future generations. Adhering to this policy, we have many initiatives within our Company aimed at fulfilling our commitment to protect the environment, some of which are linked to a specific performance measure. All of our environmental initiatives are part of an internal program called Greener Choices. Greener Choices was created to help our Company become more energy-efficient and to reduce the emissions and environmental impacts of our fleet and our facilities. Our initiatives fall under four categories: helping our employees to be more aware of what they can do to reduce their environmental impacts; creating a culture of conservation within our Company; making our facilities more energy-efficient; and reducing the emissions of our fleet of vehicles.

Skill development and knowledge retention

Given the retirement profile of our employees, we are in 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. We have embarked on an aggressive workforce renewal program that will lead to a diverse, fully engaged workforce. In addition to our partnership with four community colleges, we strengthened our association with various Canadian universities as part of a comprehensive strategy to meet our staffing needs well into the future. We also helped to establish the Ryerson University Centre for Urban Energy (the Centre). Our goal to attract and retain future sector leaders involves demonstrating that Hydro One is an employer of choice. In addition, we aim to facilitate retention and mentoring by focusing on employee engagement. We measure employee engagement across all lines of business using a confidential employee engagement survey. The grand mean score in 2010 was 3.70 out of 5, an improvement from the 2009 score of 3.63, but slightly lower than the 2010 target of 3.73. Detailed results of the 2010 survey will be used to actively address lower-performance areas and effectively implement targeted strategies designed to increase engagement levels.

Maintenance of a commercial culture that increases value for our shareholder

In 2010, we continued our commitment to maintain strong financial fundamentals. Our targets included net income and our credit ratings, which were both achieved. Net income for the year exceeded target mainly as a result of the higher temperatures experienced during the summer combined with effective cost management. A discussion of our financial results can be found on page 14 and of our liquidity and capital resources on page 18.

Our financial performance and the business environment in which we operate are taken into consideration in setting both our short-term and long-term credit ratings. During 2010, our long-term and short-term debt credit ratings remained unchanged. Credit ratings are provided by DBRS Limited, Moody's Investors Service Inc. and Standard & Poor's Rating Services Inc. (S&P). Maintaining credit ratings in the "A" category allows us to continue to access the long-term debt markets. We have been able to successfully secure sufficient and cost-effective debt financing. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

Productivity improvement and cost-effectiveness

In 2010, we remained focused on workplace productivity and its contribution as an enabler of our work programs. For our Transmission Business, productivity is measured using the cost per asset value, which is calculated as capital and maintenance program expenditures as a percentage of transmission assets. For our Distribution Business, the calculation is normalized for line length due to the rural nature of our service territory. The targets for both measures were to achieve top-quartile results when benchmarked against comparable North American utilities. Transmission and distribution productivity results for the year were both on target.

Two additional corporate measures were implemented this year. The Collaborative Planning Index measures the effectiveness of workflow between key lines of business as a result of improved integration and teamwork. The other new measure assesses the savings derived from our entity-wide information system replacement and improvement project, placed in service in 2009. In 2010, we slightly exceeded our Collaborative Planning Index target of 85%, a measure based on the average of three metrics related to the release of work, planning and order filling. We have also exceeded our target savings of $28 million related to the entity-wide information system replacement and improvement project, with actual savings of approximately $34 million. We will continue to build on the success of our new entity-wide information system to increase the cost effectiveness of work program planning, processing and execution to achieve reductions in our labour unit costs.

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.

Electricity Rates

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 temporarily 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. Effective May 1, 2010, we started migrating our customers to time-of-use (TOU) rates and have a plan in place to transition the majority of our RPP customers to TOU rates in 2011. On September 16, 2010, we filed an application with the OEB for an exemption from mandated time-of-use pricing, affecting approximately 150,000 customers located in very rural and sparsely populated portions of our service territory that are currently out of reach of our smart meter telecommunications infrastructure. In early 2011, the OEB approved our request for an extension until the end of 2012.

As announced in its 2010 fall economic update, the Province introduced the *Ontario Clean Energy Benefit Act, 2010*, which is designed to assist Ontario electricity consumers through the transition to a cleaner electricity system. Under this Act, eligible residential, farm and small business consumers receive financial assistance in the amount of a 10% credit with respect to the total cost of electricity on their bills, including tax. This assistance is being provided to eligible customers for a five-year period, beginning January 1, 2011. In January 2011, our Company issued its first bills to customers with this credit applied to their electricity costs.

Customers that are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators under the *Electricity Act, 1998*. 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.

Green Energy Act and Long-Term Energy Plan

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 other roles. 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 in August 2007. On September 17, 2008, the Province directed the OPA to review a portion of its proposed IPSP focusing on renewable energy and conservation as well as to undertake an enhanced process of consultation with First Nations and Métis communities. As a result of the Minister of Energy and Infrastructure's directive, the OEB adjourned its review of the IPSP on October 2, 2008.

On May 14, 2009, the GEA was passed in the Ontario Legislature. On September 21, 2009, to support the GEA and help bring renewable energy to the grid our Company received a letter from the then Minister of Energy and Infrastructure requesting us to immediately proceed with the planning and implementation of 20 major transmission projects. On May 7, 2010, the Minister of Energy and Infrastructure requested our Company to focus on those items that are essential to the safe and reliable operation of our existing assets or projects already under development and approved by the OEB, or are critical to the connection of renewable generation projects that have been identified by the OPA as part of the government's green energy agenda. As a result, we decided to suspend our work on the 20 major transmission projects. On August 26, 2010, the OEB released its new policy on the Framework for Transmission Project Development Plans. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open bid process.

An amendment to the deemed licence conditions of the *Ontario Energy Board Act, 1998*, as set out in the GEA, requires that distributors provide priority connection access for qualified renewable energy generation facilities and prepare plans for approval by the OEB that identify expansion or reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities.

The OPA continues to procure new, cleaner and renewable generation in Ontario. On October 1, 2009, the OPA launched the Feed-In-Tariff (FIT) Program in accordance with the directive issued by the Minister of Energy and Infrastructure to the OPA. The program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW.

On November 23, 2010, the Ministry of Energy released Ontario's LTEP which sets out the Province's expected electricity needs until 2030 and supports the continued procurement of new, cleaner generation. The LTEP addresses seven key areas: demand, supply, conservation, transmission, Aboriginal communities, capital investments and electricity prices. In conjunction with the release of its LTEP, the Province released a draft Supply Mix Directive for consultation. The draft Supply Mix Directive outlines the goals to be achieved through a new detailed long-term plan and directs the OPA to prepare an IPSP to meet those goals, as set out in the LTEP. The comment period for the draft Supply Mix Directive expired on January 7, 2011. It is anticipated that a Supply Mix Directive will be formally issued to the OPA and will form the basis for a new IPSP. The OPA is anticipated to release an updated IPSP to the OEB in 2011 for its review and approval.

The draft Supply Mix Directive to the OPA identifies five priority transmission projects over seven years. On December 22, 2010, we received a letter from the Minister of Energy updating the September 21, 2009 letter from the Minister of Energy and Infrastructure, and requesting us to immediately proceed with the necessary planning and development work to advance three of the projects in an expedited timeframe, in combined consultation with the OPA and IESO. In addition, we were asked to develop a plan to prioritize the cost-effective upgrades to our systems to safely and reliably accommodate additional renewable energy for small generation projects (see Future Capital Expenditures).

The GEA continues to provide the framework for renewable energy projects and increased conservation. A number of regulations and programs required to fully implement the legislation were introduced in the latter part of 2009.

Transmission and Distribution System Codes

In 2009, the OEB undertook a review of its codes, rules and guidelines in support of the GEA. On October 20, 2009, the OEB finalized amendments to the Transmission System Code (TSC), and adopted a "hybrid" approach to cost responsibility between transmitters and generators for "enabler facilities". Enabler facilities are lines or stations that connect two or more renewable generation facilities to the transmission grid. The hybrid option sees the initial pooling of the costs of enabler lines by the transmitter, with generators paying their pro-rata share, based on generator capacity, when ready to connect. To be eligible for this cost treatment, enabler facilities must meet certain detailed requirements outlined in the TSC.

The amendments to the Distribution System Code (DSC), finalized on October 21, 2009, revised the OEB's approach to assigning cost responsibility between a distributor and a generator for the connection of renewable energy generation facilities. The OEB defined three types of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. For generators that are connecting directly to a distributor's system, connection asset costs will continue to be borne by generators, while distributors will be required to fund all expansion costs identified in a plan, other generator-requested expansion costs up to a cap of $90,000/MW per project (with the generator paying the rest), and all renewable enabling improvements.

On June 30, 2010, Hydro One Networks Inc. (Hydro One Networks), in respect of our Distribution Business, filed an application with the OEB requesting an exemption from certain cost responsibility rules contained in the DSC for distributed generation projects under the Renewable Energy Standard Offer Program (RESOP). The application sought to deal with unanticipated costs that arose as a result of the connection of certain renewable generation facilities for generators. These generators applied to connect to our system prior to amendments made to the code on October 21, 2009. Under the rules in force at the time, all costs of connection were assigned to generators and we requested an exemption from those rules to allow for recovery of the unforeseen expenditures from ratepayers. On December 20, 2010, the OEB released its decision approving deferral accounts to capture the expenditures to be brought forward for review and approval at the next cost-of-service application.

Conservation and Demand Management

In 2009, the OPA continued to be responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination furthered initiatives undertaken by individual LDCs, including the distribution businesses of our subsidiaries Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements associated with the third phase Market Adjusted Rate of Return (MARR). Our CDM programs funded through the OPA in 2010 amounted to approximately $31 million, compared to $16 million in 2009. The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps to establish CDM targets to be met by LDCs and other licensees. The Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide LDC CDM target for Ontario's LDCs. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 are to reduce 1,330 MW of provincial summer peak demand and 6,000 GWh of cumulative energy savings, collectively.

On June 22, 2010, the OEB provided notice under the *Ontario Energy Board Act, 1998* of the creation of a proposed CDM Code for electricity distributors. The new code proposes specific CDM targets for all LDCs as directed by the Minister of Energy and Infrastructure earlier this year. The proposed allocation of the overall targets to our Company are a 256 MW reduction of provincial peak demand and a 1,208 GWh reduction of electricity consumption, representing, respectively, 19.2% and 20.1% of the total target savings established for all LDCs. The CDM Code also set out the conditions and rules that LDCs are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets. On November 1, 2010, Hydro One Networks' Distribution Business filed its CDM strategy and CDM Program application with the OEB in accordance with the requirements of the CDM Code. An oral hearing for the review and approval of our CDM application and funding of our CDM programs has been scheduled to start in March 2011.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. These meters are expected to 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 interim smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the deployment 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. In 2010, we continued our focus on building an advanced distribution solution and launched our smart grid initiative to leverage the infrastructure from our smart meter investment which is required to connect and manage large volumes of distributed generation on our distribution system (see Future Capital Expenditures).

Renewed Regulatory Framework

On October 27, 2010, the OEB announced its plan to develop a renewed regulatory framework for electricity given the significant role network investment will have in the electricity sector in the future. The renewed regulatory framework will be developed through three policy initiatives. First, the OEB will re-examine its approach to network investment planning by transmitters and distributors, including considering ways to encourage distributors and transmitters to plan their investments with the total bill impact in mind. Second, it will review its rate mitigation policy by examining alternative approaches and rate treatments that might smooth the impact of rate or bill increases on consumers. Third, it will review its current rate-making policies to ensure that they continue to facilitate the cost-effective and efficient implementation of OEB-approved plans.

Transmission Rates

Hydro One Networks

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. As part of that decision the OEB approved the disposition of export and wheeling fees liability and the transmission market-ready regulatory asset, which was factored into rates and refunded to customers over the four-year period ending December 31, 2010.

On May 30, 2008, we submitted an application to the OEB to adjust UTRs for our Transmission Business, effective January 1, 2009. On August 28, 2008, the OEB approved our application reflecting the 2008 OEB-approved revenue requirement given the full repayment to customers of the Earnings Sharing Mechanism and Revenue Difference Deferral Account as at December 31, 2008. This resulted in an average increase of approximately 9% in our revenue requirement allocation from UTRs and an approximate 1% increase on an average customer's total bill.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirements of approximately $1,233 million and $1,341 million based on an ROE of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision, effective July 1, 2009, which resulted in a reduced revenue requirement of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved ROE of 8.01% and 8.16%. The decision also required the establishment of new variance accounts to track the difference between the forecasted and actual external revenues for export services, secondary land use and net maintenance services, primarily provided to generators. In its decision, the OEB disallowed development capital expenditures of $180 million in 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, we filed supplemental evidence regarding two of the development capital projects amounting to approximately $160 million. On December 16, 2009, the OEB approved our supplemental submission increasing the approved 2010 revenue requirement to $1,257 million on the basis of an updated 2010 ROE of 8.39%. These decisions resulted in an increase in transmission tariff rates of approximately 2% and 9% for 2009 and 2010, respectively, representing a less than 1% increase on an average customer's total bill in each year.

On December 11, 2009, the OEB issued its final report on the cost-of-capital review, which concluded that the formula-based return on equity (ROE) needed to be reset and refined. On January 5, 2010, we filed a motion with the OEB to review aspects of its decision on our 2010 transmission rates, including an increase of the ROE used in calculating the 2010 revenue requirement to

9.75% from 8.39%, based on the new OEB-approved formula. On April 5, 2010, the OEB issued its decision, denying Hydro One Network's motion to vary the ROE used to calculate the revenue requirement for 2010 transmission rates. As a result of the decision, the 2010 revenue requirement remained at $1,257 million on the basis of an ROE of 8.39%.

On May 19, 2010 we submitted an application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012, which represents an estimated increase in rates of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill. The application was filed using the new OEB-approved formula for ROE and took into consideration the OEB staff report on the regulatory treatment of infrastructure investment in connection with rate-regulated activities (RRA) of Ontario distributors and transmitters, issued in January 2009.

On December 23, 2010, the OEB issued its decision effective January 1, 2011, which resulted in a revenue requirement of $1,346 million for 2011 and $1,658 million for 2012, reflecting transmission rate changes of approximately 7% in 2011 and 26% in 2012. The 2011 revenue requirement was lower than requested primarily due to a lower prescribed ROE resulting from a lower forecasted cost of debt, the denial of our request to recover the cost of capital of the construction work-in-progress for Bruce to Milton and an operation, maintenance and administration envelope reduction. Our 2012 revenue requirement was also impacted by the above noted factors, but was higher than originally submitted due to the OEB directing our Company to adopt IFRS accounting for indirect overheads capitalized, resulting in approximately a $200 million increase in 2012. Our Company was required to establish a variance account to capture any difference in the revenue requirement impact attributed to adopting IFRS capitalization accounting in 2012.

On January 17, 2011, the Power Workers Union submitted an appeal of the decision to the Ontario Superior Court of Justice (Divisional Court) asserting that the OEB failed to permit our Company to recover proposed prudently incurred operation, maintenance and administration costs and therefore, that a legal error was made. The appeal is not anticipated to affect the collection of the new 2011 transmission rates during the proceeding.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO, which facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and the IESO itself.

In 2006, the OEB initiated a process to establish an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process included 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

On December 18, 2008, the OEB issued a decision approving substantially all of the work program expenditures submitted in our 2008 cost-of-service distribution rate application. The decision was effective May 1, 2008 with an implementation date of February 1, 2009, and approved the establishment of the Revenue Recovery Account or Rider 4 to record the revenue differential between existing distribution rates and new rates from May 1, 2008. The Rider 4 is being recovered over a 27-month period, commencing February 1, 2009 and ending April 30, 2011. As part of its decision, the OEB also approved certain excess functionality expenditures for smart meters and the continuance of the 93 cents per month per metered customer. In a past proceeding, the OEB approved for recovery our expenditures incurred related to minimum functionality for advanced metering infrastructure. As a result, the difference between revenue recorded on this basis and actual recoveries received under existing rate adders are reflected as the carrying value of the regulatory asset account.

In late 2008, we filed an incentive regulation application for 2009 rates, which was updated in January 2009 to reflect the impact of the 2008 distribution rate decision. The application was filed on the basis of the OEB's third-generation IRM process, which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. On

May 13, 2009, the OEB released its decision approving the basic IRM increase and a charge of $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009 with an implementation date of June 1, 2009, and resulted in an increase of less than 1.5% on an average customer's total bill.

On July 13, 2009, we filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates reflecting our plan to invest in our network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. The application sought OEB approval of revenue requirements of approximately $1,150 million and $1,264 million based on an ROE of 8.11% and 9.09% for 2010 and 2011, respectively. The resulting distribution tariff rate increase was approximately 10% and 13% in 2010 and 2011, respectively, or approximately 3% and 4% on an average customer's total bill.

Our application included the Green Energy Plan (GEP) for our Distribution Business, filed in response to the GEA, which directed the OEB to require transmitters and distributors to file plans that would lead to the expansion of their systems to facilitate renewable energy. Our plans identified the expansion and reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities and outlined the development and implementation of the smart grid in our distribution system. Our GEP reflected changes to the *Ontario Energy Board Act, 1998*, as amended by the GEA and stipulated in Ontario Regulation 330/09. The amendments provided a new mechanism for rate protection, whereby some or all of the OEB-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of renewable energy generation to its distribution system may be recovered from all provincial ratepayers, rather than solely from ratepayers of the distributor making the investment.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The 2010 and 2011 revenue requirements were lower than originally requested, reflecting reductions in operation, maintenance and administration expenses, capital expenditures and working capital requirements. As part of its decision, the OEB also approved certain distribution-related deferral account balances sought by our Company in our application, including retail settlement variance accounts, the remainder of a regulatory asset recovery account, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011. Further, the OEB requested the establishment of deferral accounts to track the difference between the revenue recorded on the basis of our GEP expenditures incurred and actual recoveries received under the approved funding adder or rider.

The 2010 distribution rates were implemented on May 1, 2010, reflecting a rate increase of approximately 9.3%, or approximately 3% on an average customer's total bill. Our 2011 revenue requirement was adjusted to reflect the OEB's decision to decrease OM&A by $40 million and was adjusted to reflect a $44 million capital program reduction. On November 15, 2010, the OEB issued its cost of capital parameter updates for rates effective January 1, 2011. The new ROE value for 2011 is 9.66%. Applying this lower ROE produces a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement results in an average distribution rate increase of approximately 8.7% for 2011, or 3.0% on an average customer's total bill.

Hydro One Brampton

On November 7, 2008, our subsidiary Hydro One Brampton filed an application for 2009 rates on the basis of the OEB's second-generation IRM policy, which incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 13, 2009, the OEB released its decision and revised rates, including an amount of $1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009. Overall, the impact on an average customer's total bill was marginal.

On November 6, 2009, an application for 2010 distribution rates was filed on the basis of the OEB's second-generation IRM process. On April 13, 2010, the OEB released its decision regarding this rate application approving our submission on the basis of the OEB's cost-of-capital and second-generation IRM policies. The revised rates were implemented on May 1, 2010 and resulted in a reduction of approximately 8.3%, or 2.2% on an average customer's total bill in the year.

On June 30, 2010, we submitted a 2011 cost-of-service application, which was subsequently adjusted on September 2, 2010 to reflect the Canadian Accounting Standards Board's decision to allow the deferral of the adoption of International Financial Reporting Standards (IFRS) implementation for rate-regulated entities to January 1, 2012. The updated submission was filed on November 8, 2010 and requested a revenue requirement of approximately $63 million. The oral hearing concluded on December 7, 2010 and we expect a decision in the first quarter of 2011.

Hydro One Remote Communities Inc.

On August 29, 2008, we filed a 2009 cost-of-service rate application proposing an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all work program expenditures and the proposed rate increase of 4.4% effective May 1, 2009, resulting in a 4.4% increase to an average residential customer's total bill.

On November 4, 2009, we filed an application for 2010 rates under the OEB's third-generation IRM, which sought approval of an increase to basic rates for the distribution and generation of electricity effective May 1, 2010. The increase reflected the standard inflationary adjustments incorporated in the third-generation IRM applications. On April 14, 2010, the OEB issued a decision regarding this rate application under the OEB's third-generation IRM policies. The revised rates were approved for implementation on May 1, 2010 and reflect an increase of approximately 0.4%, the overall impact of which on an average customer's total bill is marginal.

On October 15, 2010, an application for 2011 distribution rates was filed on the basis of the OEB's third-generation IRM seeking approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. We expect to update our requested rate increase when the OEB issues its inflation and productivity factors for IRM filers in the first quarter of 2011.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	**2010**	2009	$ Change	% Change
Transmission	**1,307**	1,147	160	14
Distribution	**3,754**	3,534	220	6
Other	**63**	63	-	-
	5,124	4,744	380	8
Average annual Ontario 60-minute peak demand (MW) [1]	**21,572**	20,798	774	4
Distribution – units distributed to customers (TWh) [1]	**29.1**	28.9	0.2	1

[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. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenue associated with transmitting excess generation to surrounding markets and ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $160 million, or 14%, compared to 2009. The OEB rendered its decision on our 2009 and 2010 transmission rate application on May 28, 2009. The decision followed extensive oral and written reviews of our evidence submitted for the necessary funding in support of system requirements. The resulting tariff increases approved effective July 1, 2009 and January 1, 2010 support our in-service capital investments in respect of the Province's supply mix policy, including the phase-out of coal-fired generation and addressing aging infrastructure. These increases resulted in higher revenues of $119 million. We also experienced higher revenues of $12 million associated with certain OEB-approved deferral accounts as a result of the decision.

Also contributing to increased revenue was the higher average monthly peak demand experienced during the year. The average annual Ontario 60-minute peak demand and the overall related load were 774 MW and 9,282 MW higher than last year, respectively, resulting in higher revenues of $37 million. Weather was generally milder over the winter months and unseasonably hot during the summer months, compared to the prior year. Our system performed well under these extreme conditions.

Transmission tariff revenue increases were partially offset by lower ancillary revenues of approximately $8 million due to the impact of the May 28, 2009 OEB decision. Consistent with this decision, ancillary revenues received in excess of OEB-approved levels are recorded in a regulatory liability account and are not recognized as revenue.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. 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 $220 million, or 6%, compared to 2009, including an increase in the recovery of higher purchased power costs of $148 million, as described below in the section "Purchased Power."

Increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On May 13, 2009, the OEB approved new tariff rates under the third-generation IRM effective May 1, 2009. On April 9, 2010, the OEB approved new tariff rates following our cost-of-service application effective May 1, 2010. Both decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of the distribution system, including those to support renewable distributed generation. The combined impact of these decisions was an $82 million increase. These tariff rate increases support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers throughout Ontario. We also experienced higher revenues of $7 million associated with certain OEB-approved deferral accounts for the year.

Distribution revenue increases were partially offset by lower energy consumption, resulting primarily from the milder weather in the first quarter of the year, partially offset by unseasonably hot weather during the summer months, which reduced our distribution revenues by $3 million compared to last year. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective April 30, 2010, resulting in a revenue reduction of $16 million compared to last year.

We also experienced higher ancillary revenues of approximately $2 million compared to the prior 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 comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) 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 Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both adjusted twice annually. The vast majority of RPP customers are anticipated to be on time-of-use billing by the end of June 2011. 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 for the reporting period 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, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5
November 1, 2010	1,000	750	6.4	7.4

RPP Time-of-Use	Rates (cents/kWh)		
Effective Date	On Peak	Mid Peak	Off Peak
May 1, 2010	9.9	8.0	5.3
November 1, 2010	9.9	8.1	5.1

Purchased power costs increased in 2010 by $148 million, or 6%, to $2,474 million for the year compared to 2009. The increase in our purchased power costs was primarily due to the impact of changes in the OEB's RPP rate for residential and other eligible customers of $84 million, higher transmission charges of $33 million due to the OEB's transmission rate decisions effective July 1, 2009 and January 1, 2010, higher purchased power costs for customers that are not eligible for the RPP of $33 million and higher demand for electricity of $13 million. The effect of these increases was partially offset by lower wholesale market service charges levied by the IESO of $15 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are 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)	**2010**	2009	$ Change	% Change
Transmission	**416**	438	(22)	(5)
Distribution	**602**	564	38	7
Other	**60**	55	5	9
	1,078	1,057	21	2

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $22 million, or 5%, in 2010 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. We substantially completed our work program requirements while focusing on productivity. Effective delivery of our maintenance program, particularly on power equipment, enabled us to reallocate resources to the timely delivery of our expanded capital programs. Given favourable weather conditions in the first half of the year, together with productivity improvements resulting from the implementation of our entity-wide information system, we were able to effectively execute our work programs. As a result, we experienced lower planned line maintenance expenditures, lower expenditures in our forestry programs and lower requirements for engineering support. Our expenditures in support of our transmission system have also decreased by $8 million, primarily reflecting the redirection of resources and the elimination of capital tax by the Canada Revenue Agency (CRA) effective July 1, 2010, partially offset by a one-time contribution of $27 million to the pension plan during the last quarter of this year.

Distribution

Operation, maintenance and administration expenditures required to maintain our low-voltage distribution system increased by $38 million, or 7%, compared to last year. Our work program expenditures increased by $11 million primarily as a result of favourable weather allowing us to deliver a larger forestry program in a cost-effective manner. Additionally, we experienced increased requirements within our customer care and engineering support programs, as well as within our smart meter program due to ongoing operational costs for installed meters. These expenditures were partially offset by lower expenditures within our lines maintenance program, including storm restoration, inspection and testing of pole transformers and field meter readings as installed smart meters begin to reach the required level of reliable communication. Our expenditures in support of our distribution system were higher by $27 million, reflecting a one-time contribution to the pension plan of $21 million during the last quarter of this year as well as the redirection of resources, partially offset by the elimination of capital tax by the CRA effective July 1, 2010.

Depreciation and Amortization

Depreciation and amortization expense reflect a net increase of $46 million, or 9%, to $583 million in 2010 compared to last year. This was mainly attributable to increased depreciation and amortization expense of $45 million from new assets coming into service, consistent with our ongoing capital work program. A further increase of $7 million was the result of increased fixed asset removals associated with our capital projects. Amortization of regulatory and other assets decreased by $6 million due to the completion of the amortization of a distribution regulatory account during the second quarter of this year, partially offset by increased amortization of our environmental regulatory asset related to higher expenditures necessary to comply with Environment Canada's regulations on the removal of polychlorinated biphenyls.

Financing Charges

Financing charges increased by $34 million, or 11%, to $342 million for 2010 compared to last year. Financing charges increased by $40 million mainly due to an increased average level of debt, partially offset by a lower average effective interest rate. Lower capitalized interest of $4 million also contributed to higher financing charges this year. Although we had higher levels of construction in progress, we capitalized less interest due to lower OEB-approved interest capitalization rates. These increases were partially offset by changes in interest income and other ancillary amounts which reduced overall financing charges by $10 million.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes (PILs) to the 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, the liability method is used. The change in future taxes relating to both the unregulated and regulated businesses, in respect of temporary differences that are not considered for the rate-making process, results in a future tax provision that is charged to the income statement. The change in future taxes relating to temporary differences of the regulated business that are considered for the rate-making process results in a regulatory asset or regulatory liability.

The provision for payments in lieu of corporate income taxes increased by $10 million, or 22%, to $56 million compared to 2009. The increase was primarily due to higher pre-tax income in the year, partially offset by higher net temporary differences related to certain regulatory accounts and a reduction in the statutory rate from 33.0% to 31.0%.

Net Income

Net income of $591 million was higher by $121 million, or 26%, compared to 2009 results. Revenues were affected by the OEB-approved rate decisions that support investments in respect of supply mix policies, including the phase-out of coal-fired generation, necessary maintenance and investment requirements of our systems, and investments to address aging infrastructure. These investments in our transmission and distribution systems are reflected in the increase of approximately $1.1 billion in our fixed assets from the prior year. Revenues were also affected by a higher average monthly peak demand due to hotter than average weather during the summer months, partially offset by milder weather during the winter months. These impacts were partially offset by a one-time contribution to our pension plan, which was enabled by our effective cost management over operating costs in the year.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2009 through December 31, 2010. This information is derived from our unaudited interim Consolidated Financial Statements, which, in the opinion of management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include the 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)	**2010**				2009			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues[1]	**1,280**	**1,360**	**1,165**	**1,319**	1,207	1,144	1,090	1,303
Net income[1]	**99**	**218**	**105**	**169**	111	100	82	177
Net income to common shareholder[1]	**94**	**214**	**100**	**165**	106	96	77	173

[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.

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 resources 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)	**2010**	2009
Operating activities	**1,164**	892
Financing activities		
Long-term debt issued	**1,500**	1,150
Long-term debt retired	**(600)**	(400)
Short-term notes payable	**(55)**	55
Dividends paid	**(28)**	(188)
Investing activities		
Capital expenditures	**(1,570)**	(1,566)
Long-term investments[1]	**(250)**	-
Other financing and investing activities	**37**	15
Net change in cash and cash equivalents	**198**	(42)

[1] Represents $250 million of Province of Ontario Floating Rate Notes.

Operating Activities

Net cash from operating activities increased by $272 million to $1,164 million compared to last year. This increase primarily reflects higher net income and changes to accounts payable balances due to increases such as our purchased power costs related to the demand for electricity, timing of prepayments from customers and increased taxes payable related to the implementation of the HST. Changes in accounts receivable balances and in certain regulatory accounts also impacted net cash from operations.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holdings of Province of Ontario Floating Rate Notes.

At December 31, 2010, we had no short-term notes outstanding. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program together with anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. During the second quarter, we increased the amount of our $500 million revolving credit facility, entered into in the first quarter, to $1,250 million and we extended the term of the facility to June 2013. Also in the second quarter, we cancelled the $750 million revolving credit facility which would have matured in August 2010.

At December 31, 2010, we had $7,775 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2011 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August 2011 is $3,000 million, of which $1,250 million was remaining and available as at December 31, 2010.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	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 agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide 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 as of December 31, 2010.

In 2010, we successfully issued $1,500 million in cost-effective long-term debt under our MTN Program, consisting of $1,000 million in the first quarter and $500 million in the third quarter. We repaid $600 million in maturing long-term debt, including $400 million in the second quarter and $200 million in the fourth quarter. In 2009, we issued $1,150 million in long-term debt under our MTN Program and repaid $400 million in maturing long-term debt. During 2010, we reduced our short-term notes by $55 million, all in the first quarter. In 2009, we increased our short-term notes by $55 million.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations and maintaining the deemed regulatory capital structure. Financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations are also taken into consideration. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

In 2010, we paid dividends to the Province in the amount of $28 million, consisting of $10 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $170 million and preferred dividends of $18 million. In 2010, cash dividends per common share were $100 compared to $1,700 per common share in 2009. Cash dividends per preferred share were $1.375 in each of 2010 and 2009.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

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)	**2010**	2009	$ Change	% Change
Transmission	**936**	918	18	2
Distribution	**629**	643	(14)	(2)
Other	**5**	5	-	-
	1,570	1,566	4	-

Transmission

Transmission capital expenditures increased by $18 million in 2010 to $936 million, compared to 2009. Expenditures to expand and reinforce our transmission system were $524 million, representing an increase of $7 million over last year. These expenditures primarily consist of those on inter-area network and local area supply development projects. We completed a number of multi-year projects and put them in service and other projects are beginning to progress. We continued to invest in a number of inter-area network upgrade projects to support the Province's supply mix objectives for generation. We also continued to make investments in our local area supply projects to address growing loads. These expenditures were partially offset by a reduction in expenditures associated with load customer connection projects as well as local area supply and inter-area network projects that were substantially completed this year.

Inter-area network upgrades with significant expenditures included the Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area, and the Northeast Transmission Reinforcement Project, which will increase the North-South interface transfer capability to access available northern generation. The Northeast Transmission Reinforcement Project is comprised of work to install static var compensators (SVCs) at Porcupine and Kirkland Lake Transformer Stations. In addition, we are installing SVCs at Nanticoke and Detweiler Transformer Stations, which in the short term will support increased generation from the Bruce Nuclear facility and in the longer term, will enhance the transfer capability between Southwestern Ontario and the Greater Toronto Area (GTA). The installation of SVCs represents new technology to our system and we successfully put one of them in service at the end of the year. These investments were partially offset by lower expenditures associated with the installation of capacitor banks in Southwestern Ontario, which is substantially complete. This equipment provides interim protection to the Bruce Nuclear facility and expands transmission capacity in Southwestern Ontario. In addition, we incurred lower expenditures associated with the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro-Québec interconnection. This work was substantially completed in the fourth quarter of the year.

Local area supply projects with expenditures in the period include our Woodstock Area Transmission Reinforcement Project, which will increase capacity to ensure supply reliability in the Woodstock area, and our Switchyard Reconstruction Project at our Burlington Transformer Station, which will increase the load supply capacity to ensure reliability of supply to customers in the area. The GTA West Transmission Reinforcement Project, which has increased capacity to ensure supply reliability in the area, as well as the Hurontario Switching Station to Jim Yarrow Municipal Transformer Station connection, which has increased transmission capacity in the Western Brampton area to allow for future load growth, were both substantially completed in the first quarter of this year, contributing to the reduction in expenditures compared to the prior year. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $309 million, representing an increase of $25 million compared to 2009. This increase was primarily due to increased requirements related to the refurbishment and replacement of end-of-life lines and stations and to higher targeted replacements of aging components, specifically within our breaker installation program. We also experienced increased expenditures within our protection and control equipment program compared to the prior year. These increases were partially offset by lower expenditures within our Spare Transformer Purchase and Hub Replacement Programs.

Our other transmission capital expenditures were $103 million, representing a decrease of $14 million compared to the prior year. This reduction from the prior year was due to expenditures in 2009 on our investment in an entity-wide information system replacement and improvement project which replaced end-of-life systems and improved productivity, the second phase of which was completed during the third quarter of last year. Further impacting the period are expenditures incurred to enhance information security at our Ontario Grid Control Centre, which were lower compared to the prior year as we completed a number of enhancements to meet North American Electric Reliability Corporation requirements in 2009. Partially offsetting these reductions were higher expenditures in 2010 related to the strategic purchase of power transformers in order to ensure transmission reliability through availability of critical long delivery lead time items.

Distribution

Distribution capital expenditures decreased by $14 million to $629 million in 2010, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $304 million, representing a reduction of $20 million compared to last year. We experienced reductions relating to expenditures on planned line development projects and demand line work for new connects and upgrades mainly due to a reallocation of resources to sustaining line work for line relocations. The reduction was also due to the substantial completion of smart meter installations across the province at the end of last year. During the year, these lower expenditures related to installations were partially offset by expenditures on the smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. Smart meter installations continued throughout the year as our total cumulative number of installations exceeded 1,314,000 as at December 31, 2010, thus nearing the program's total target. We currently have over 1,140,000 meters enabled to support time-of-use billing and continue our efforts to migrate our customers to time-of-use pricing; over 553,000 of our customers are now consuming power based on time-of-use pricing. Our program is one of the largest utility smart meter deployments in North America. These reductions were partially offset by the initiation of our Smart Grid Program which will enhance our operations and support distributed generation.

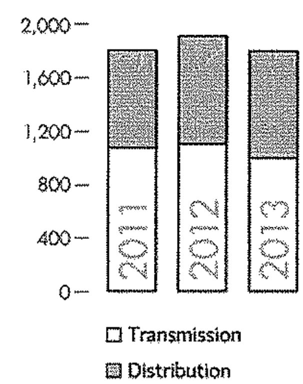
Expenditures to sustain our distribution system were $275 million, an increase of $28 million from 2009. This increase was primarily a result of higher requirements for transport and work equipment and the re-allocation of resources from planned line development projects to demand line work for line relocations in support of municipal road widening projects which are partially funded by the municipalities. These increases were partially offset by reduced expenditures as a result of fewer storms in 2010.

Our other distribution capital expenditures were $50 million, representing a reduction of $22 million from 2009. This reduction primarily reflects our higher prior period investments in our entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures in 2011 are budgeted at approximately $1.8 billion. The 2011 capital budgets for our Transmission and Distribution Businesses are about $1,050 million and $750 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to be approximately $1.9 billion in 2012 and approximately $1.8 billion in 2013. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately $550 million in 2011, $700 million in 2012 and $700 million in 2013. Development projects, including smart grid, inter-area network upgrades that reflect supply mix policies to phase out coal generation, local area supply requirements and requirements to enable distributed generation, are budgeted at approximately $950 million in 2011, $950 million in 2012 and $850 million in 2013. These development investments also reflect customer demand work, distributed generation connections and the rollout of smart grid. Other capital expenditures amount to approximately $300 million in 2011, $250 million in 2012 and $250 million in 2013. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our entity-wide SAP platform.

Future Capital Expenditures
(CAD $ millions)



Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2011 to 2013, amounting to about $3.2 billion, including 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. The investment plan includes targeted component replacements of air blast circuit breakers, switchgear, autotransformers and wood pole structures to maintain the performance of assets. Also, the reconstruction of transformer stations is planned for the Burlington TS 115 kV, Leaside, Hearn and Manby stations to ensure future reliability. These sustaining investments are necessary to ensure that we will continue to meet all regulatory, compliance, safety and environment objectives.

Inter-area network projects, required to accommodate new generation related to supply mix policies, include our Bruce to Milton Transmission Reinforcement Project to connect nuclear generation and new wind generation in the Huron-Grey-Bruce area. This project is anticipated to be in service in 2012. We are also installing station equipment, including SVCs in Southwestern Ontario, to increase transmission capacity. This equipment will mitigate congestion and enhance the transfer capability between Northern Ontario and Southern Ontario and the transmission system north of Sudbury enabling new hydroelectric generation.

The budgeted capital expenditures do not include any amounts associated with new lines projects articulated in the September 21, 2009 letter to us from the then Minister of Energy and Infrastructure. We suspended work on those projects after the Minister of Energy and Infrastructure requested our Company to focus on those items that are essential to the safe and reliable operation of our existing assets or projects already under development and approved by the OEB, or are critical to the connection of renewable generation projects that have been identified by the OPA as part of the government's green energy agenda. In addition, in August 2010, the OEB introduced competition for transmission expansion projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work to advance specified transmission projects and upgrades to the system that will safely and reliably accommodate additional renewable energy from small generation projects. According to the LTEP, we are expecting to receive direction to carry out the three specified projects. These transmission projects, which are identified in the LTEP, include:

- Southwestern Ontario Series Compensation
- Reconductoring Sarnia to London circuits
- New transmission line west of London

While our current budget does not include the estimated capital expenditures associated with these projects and upgrades to the system, they could be up to approximately $1 billion over a period to the in-service dates of these projects.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon various approvals including OEB leave-to-construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities, as well as the timing and level of generator contributions for enabling facilities under recent amendments to the TSC. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates, including those recently requested by the Ministry of Energy.

Distribution

Capital expenditures for the period 2011 to 2013 are estimated to be approximately $2.3 billion, including capital expenditures to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There is a continuation of investments to replace end-of-life equipment and components, implement smart grid and focus on wood pole replacements and submarine cables to address deteriorating assets. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Our Distribution sustainment work program has been reduced consistent with the decision on our distribution application for the 2010 and 2011 rate years and as a result our work program will include in it a gradual increase in our intended Wood Pole Replacement Program to address the aging poles and deterioration.

Distribution development expenditures over the period are primarily related to customer demand work such as connections and upgrades, smart grid, distributed generation connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2011 and 2012 period we are managing a significant number of projects throughout the province to address load growth and the stress on our system components.

Distributed generation expenditures are based on our estimate of the number of anticipated connections, taking into account the most recent data available from the OPA. Although distributed generation demand is expected to increase over the planning period, connection work is contestable and therefore the volume of work could fluctuate.

The Company's current billing system is near end of life, and costly to maintain and operate. The replacement of this system is anticipated to commence in 2011 and be completed by 2014.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations under Canadian GAAP, as well as other major commercial commitments:

December 31, 2010 (Canadian dollars in millions)	**Total**	**2011**	**2012/2013**	**2014/2015**	**After 2015**
Contractual Obligations *(due by year):*					
Long-term debt – principal repayments	7,775	500	1,200	1,000	5,075
Long-term debt – interest payments	6,599	405	732	614	4,848
Inergi LP (Inergi) outsourcing agreement[1]	569	143	274	152	-
Operating lease commitments	53	5	14	9	25
Environmental and asset retirement obligations[2]	391	23	60	73	235
Total Contractual Obligations[6]	15,387	1,076	2,280	1,848	10,183
Other Commercial Commitments *(by year of expiry):*					
Bank line[3]	1,250	-	1,250	-	-
Letters of credit[4]	114	114	-	-	-
Guarantees[4]	326	326	-	-	-
Pension[5]	307	145	162	-	-
Total Other Commercial Commitments	1,997	585	1,412	-	-

[1] On May 1, 2010, the Company extended the Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[2] We record a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands as well as asset retirement obligations for the removal of asbestos-contaminated material from our facilities and the decommissioning and removal of our switching station located at Ontario Power Generation's Abitibi Canyon Generating Station. The expenditure pattern reflects our planned work program for the period.

[3] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks which matures in June 2013.

[4] We currently have bank letters of credit of $113 million outstanding relating to retirement compensation arrangements (RCAs). The other $1 million included in letters of credit pertains to operating letters of credit. On November 1, 2010, we increased our letter of credit related to RCAs to approximately $113 million from $107 million. 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 and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2011 are based on an actuarial valuation filed in September 2010 and effective December 31, 2009. Our annual pension contributions for 2011 and 2012 will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we estimate our minimum pension contributions to be approximately $145 million in 2011 and $149 million in 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012.

[6] 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 agreements are considered individually material, and the majority do not extend beyond December 31, 2011.

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 are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures. Expenditures resulting from our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows.

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 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. In January 2010, we purchased $250 million of Province of Ontario Floating Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

The load is expected to decline in 2011 due to the impact of CDM and Embedded Generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 1.0%, with the industrial sector slightly outperforming residential and commercial sectors. The load impact of CDM and Embedded Generation is expected to have a substantial negative impact on load growth of approximately 2.0% and 0.3%, respectively. On the whole, load is expected to decline by about 1.3%. A reduction in load, beyond our load forecast included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of our revenue requirements filed with the OEB. The first component impacted by interest rates is the return on equity. The OEB-approved adjustment formula for calculating return on equity will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in the current OEB formula for determining our rate of return on equity would reduce our Transmission Business' results of operations by approximately $16 million and our Distribution Business' results of operations by approximately $10 million. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, blanket orders, vendor alliances and manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities as of December 31, 2010, which is comprised of a $1,250 million syndicated bank line of credit and the holding of $250 million of Province of Ontario Floating Rate Notes. In 2010, we continued issuing sufficient cost-effective debt financing through the MTN Program and Commercial Paper Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions continue to improve from the credit crisis of late 2008.

Pension

During 2010, the deferred pension asset reported on our Balance Sheet increased by $36 million to $460 million. We contributed $143 million into our pension plan in 2010 and made an additional payment of $48 million in December. We incurred $154 million in net periodic pension benefit cost. On an accounting basis, the 2009 unfunded benefit obligation of $230 million increased by $67 million to $297 million. The plan experienced positive returns of about 9.96% in the year. However, the plan was also impacted by an increase in the accrued benefit obligation, primarily as a result of a decrease in the discount rate used for accounting purposes (see Critical Accounting Estimates – Employee Future Benefits).

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, comprised of 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 reviewing of our risk profile and practices, and our Executive Vice-President and 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, are 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 Executive Vice-President and 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 influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our Company. Pursuant to such agreement, in September 2008 the Province made a declaration removing certain powers from our Company's directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi LP. In 2009, the Province required Hydro One, among other agencies, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Hydro One's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province 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 proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us, which could have a material adverse effect on our business.

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 safe and reliable service on a timely basis and earn the approved rates 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 materially 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 affected by successful CDM programs. The recently proposed LTEP directs the OPA to achieve interim CDM targets of 4,550 MW of provincial summer peak demand and 13 TWh of cumulative energy savings by the end of 2015. The Minister of Energy and Infrastructure's March 31, 2010 directive set a province-wide LDC CDM target of 1,330 MW and 6,000 GWh for the period 2011-2014. Our targets have been set at 214 MW and 1,130 GWh for the period 2011-2014. These expectations are factored into our revenue requirements for OEB approval, to ensure that the targeted CDM accomplishments do not result in deteriorated revenues. There is a risk that our revenues would be reduced if these targets are exceeded. In September 2010, the Conservation and Demand Management Code for Electricity Distributors was established and sets out the obligations and requirements that licensed distributors must comply with in relation to the CDM targets set out in their licenses. This code also sets out the conditions and rules that licensed distributors are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets. The implementation of this code could further deteriorate revenues without appropriate compensation. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of any such compensation mechanism is yet to be determined. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

In response to the LTEP, we expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

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 asset impairment and charges to our results of operations, which could have a material adverse effect on our Company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2011 and 2014, including $500 million maturing in 2011 and $600 million maturing in 2012. We plan to incur capital expenditures of approximately $1.8 billion in 2011 and capital expenditures are expected to increase to approximately $1.9 billion in 2012. Cash generated from operations, after the payment of expected dividends, 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 materially 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 Company.

Risk Associated with Transmission Projects

The amount of power that can flow through our transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our network to reliably transmit power from new and existing generation sources (including expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: environmental approval(s); receipt of OEB approvals, which can include expropriation; and appropriate consultation processes, and where appropriate, accommodation with First Nations and Métis who may potentially be affected by a project. Obtaining these approvals and carrying out these processes may also be impacted by public opposition to the proposed site of transmission investments; thus there is a risk that necessary approvals may not be obtained in a timely fashion or at all. This will adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our Company.

With the introduction on August 26, 2010 of the OEB's competitive transmission project development planning process, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92, Leave to Construct, applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are only recoverable by the successful proponent.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital and maintenance programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, including the fact that opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities. Lead times for material and equipment have also increased substantially due to increased demand and limited vendor capability.

Adjustments to accommodate these external dependencies have been made in our planning process. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our Company.

Work Force Demographic Risk

By the end of 2010, approximately 18% of our employees were eligible for retirement and by 2012 there may be about 22% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We have already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions. Moreover, we must also 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, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. Given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our Company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful 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 (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our Company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's polychlorinated biphenyl (PCB) regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025 while our LAR expenditures are expected to be incurred over the period ending 2020. 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.

As a result of regulatory changes, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. With the assistance of an external expert, we completed a study to estimate the expenditures associated with removing such materials from our facilities. We used this information to record an asset retirement obligation at December 31, 2010.

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 result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our Company.

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, or governments decide to implement exposure limits, 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. Any of these could have a material adverse effect on our Company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. 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 transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

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 which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. Although security and system disaster recovery controls are in place, system failures or security breaches could have a material adverse effect on our Company.

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 triennial basis. The most recently filed valuation was prepared as at December 31, 2009 and was filed in September 2010. Our Company contributed $145 million to its pension plan in respect of 2010 to satisfy minimum funding requirements. A one-time additional payment of $48 million was made in December 2010. Contributions beyond 2010 will depend on investment returns, changes in benefits and actuarial assumptions, and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our Company, and this risk may be exacerbated as the quantum of required pension contributions increase.

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. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our Company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic 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 forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' net income by approximately $16 million and our Distribution Business' net income by approximately $10 million. Our net income is 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.

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 and by monitoring the financial condition of counter-parties. 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. The failure to properly manage these risks could have a material adverse effect on our Company.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (Society). Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2011 and the existing Society collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our Company.

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, 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 $761,500 that we paid to these Indian bands and bodies in 2010. If we cannot obtain consents from the Indian bands and bodies, 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 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 our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our outsourcing services agreement with Inergi LP, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi LP is terminated for any reason, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. 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 by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

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, 2010 amounted to $1,055 million and principally relate to future income tax, environmental costs and the pension variance account. We have also recorded regulatory liabilities amounting to $612 million as at December 31, 2010. These amounts pertain primarily to deferred pension, the external revenue variance account, future income tax 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. 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 satisfy 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 assets contaminated with PCB-laden 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 in order to generate future cash flow information. A long-term inflation assumption of 2% has been used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded. Consistent with the requirements of Environment Canada's PCB regulations issued on September 17, 2008, estimated future PCB remediation expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded.

Recording a liability now 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; the number of assets to be inspected, tested and mitigated; oil volumes; and contamination levels of equipment with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future 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 (the Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions in respect of 2010 were approximately $193 million, $145 million of which was based on an actuarial valuation effective December 31, 2009. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012, and will depend on 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 6.50% 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 63% exposure to equities, 33% to fixed income and 4% 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 intended to be 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. In the short-term, the plan can experience aberrations in actual return. In 2010, the return on pension plan assets was higher than this long-term assumption.

The 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, 2010 decreased to 5.75% from 6.50% used at December 31, 2009 in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

Yields on AA corporate bonds decreased by approximately 70-120 basis points between December 31, 2009 and December 31, 2010. Based on the duration of the plan's liabilities, discount rates would be 5.75% per annum for each of the pension plan, the post-retirement benefit plan and the post-employment plan. The overall discount rate applied to all plans for liability valuation purposes as at December 31, 2010 was 5.75%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has increased from approximately 2.50% per annum as at December 31, 2009 to within the range of 2.25% - 2.50% per annum as at December 31, 2010. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is too high to be used as a long-term assumption and as such, has used a 2.00% per annum inflation rate for liability valuation purposes as at December 31, 2010.

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 $15 million per year and an increase in the year-end obligation of about $185 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 the cost of fixed assets.

Goodwill and Asset Impairment

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 2010 and we determined that the carrying value of our goodwill has not been impaired.

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date for any of our businesses.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011, with comparative data also reported under IFRS. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their adoption of IFRS for one year. We plan on adopting the one-year deferral and therefore will adopt IFRS for our fiscal year beginning on January 1, 2012.

In anticipation of the 2008 decision from the AcSB, we commenced our IFRS conversion project in 2007. The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high-level review and identification of the major differences between current GAAP and IFRS in all subject areas, resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our Company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all our policy analyses. We are currently engaged in the implementation phase which is the final phase of our project. We are preparing to begin tracking our comparative results under IFRS next year. Our teams continue to monitor progress relative to key milestones, monitor developments of both the International Accounting Standards Board (IASB or the Board) and the AcSB, update recommendations and develop financial reports. We continue to have ongoing dialogue with our external auditors about possible outcomes of our project.

We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as standards continue to evolve.

Accounting Policies

The areas with the highest potential to significantly impact our Company upon conversion to IFRS, identified during the diagnostic phase, are regulatory assets and liabilities, fixed-assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1).

Property, Plant and Equipment

On May 6, 2010, the IASB issued the omnibus *Improvements to IFRS*, which included an amendment to IFRS 1 applicable to entities with RRA. It includes transition relief for first-time adopters by offering an optional exemption to use the carrying amount of fixed assets or intangible assets as deemed cost on the transition date when the carrying amount includes costs that would not otherwise qualify for capitalization. We will elect this exemption for our regulated businesses.

Regulatory Assets and Liabilities

RRA is not permitted under IFRS. RRA affects the timing of the accounting recognition of costs, revenues, losses and gains. The inability to recognize regulatory assets and liabilities after implementing IFRS in 2012 will impact our statement of operations by causing a change in the timing of recognition of these amounts. In the absence of rate-regulated accounting, the write-off of our regulatory assets and regulatory liabilities would have resulted in a net reduction to retained earnings of approximately $249 million as at December 31, 2010.

In-Progress Construction and Development

Current IFRS are significantly different from Canadian GAAP in terms of the expenditures that can be capitalized to in-progress construction and development programs and projects. Certain fixed asset and intangible asset expenditures are ineligible for capitalization under IFRS. In the absence of rate-regulated accounting, the estimated impact on our financial statements would have been a reduction of approximately $300 million in capital expenditures and an increase of approximately $300 million in operations, maintenance and administration expenditures had this accounting been followed in 2010. For 2012 rates, the OEB directed our Company to adopt this change in accounting classification for ineligible expenditures in determining the revenue requirement of our Transmission Business. We currently have approval for a deferral account for such expenditures within our Distribution Business and we anticipate applying for revenue requirement treatment, consistent with that directed for our Transmission Business, in our next distribution rate application.

Employee Future Benefits

In the absence of RRA, the continuation of accounting for expenditures related to employer-sponsored pension plans on a cash basis is not permissible. Regulatory assets and liabilities, representing the cumulative difference between our Company's pension contributions currently accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP, would not meet the definition of assets or liabilities under IFRS and hence will require de-recognition at the IFRS transition date. We have assessed our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. The possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits* (IAS 19). In the absence of rate-regulated accounting, we intend to recognize a retrospective adjustment for these amounts under IAS 19, without the IFRS 1 exemption. The impact of adopting IAS 19 retrospectively at December 31, 2010 would have been a reduction to retained earnings of $319 million.

In April 2010, the IASB published an exposure draft, *Defined Benefit Plans (Proposed Amendments to IAS 19 Employee Benefits)*, with significant implications for both financial position and income reporting. Deferred recognition of actuarial gains and losses would be eliminated and instead all changes in the defined benefit obligation and in the fair value of plan assets would be recognized in the Statement of Comprehensive Income when those changes occur. The exposure draft also proposed a new presentation approach where the changes in the defined benefit obligation and the fair value of plan assets would be segregated and separately disclosed as service cost, finance cost and re-measurement adjustments. Service cost and finance cost components would be recognized in the Statement of Operations. The re-measurement adjustments representing actuarial gains and losses would be recognized as part of other comprehensive income. As per the IASB's revised timeline, the final standard is expected in the first quarter of 2011 with an effective date not earlier than 2013. The new accounting standard when adopted in 2013 or in later years will result in higher volatility in the Statement of Comprehensive Income due to the recognition of the full amount of actuarial gains and losses.

Payments in Lieu of Corporate Income Taxes

We recognize future tax assets and liabilities in accordance with Canadian Institute of Chartered Accountants Handbook section 3465, *Income Taxes*, which was amended effective January 1, 2009 to bridge the convergence to IFRS. As such, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. Without RRA, the impact on our provision for payments in lieu of corporate income taxes would be recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs for the year ended December 31, 2010 would have been higher by approximately $100 million including the impact of a change in substantively enacted tax rates.

OEB Consultation

On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

On February 24, 2010, the OEB issued a letter to all licensed electricity distributors and rate-regulated natural gas utilities for the purpose of clarifying the OEB's view released in July on accounting for overhead costs in the cost of new capital works effective January 1, 2011. The OEB stated in the letter that it would be requiring full compliance with IFRS requirements, including those in IAS 16, *Property, Plant and Equipment* (IAS 16), as applicable to non-regulated enterprises and only where the OEB authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable. We continue to assess this guidance in light of the AcSB's revised implementation date.

On November 8, 2010, the OEB published an amendment to a report it made on its policy, *Transition to International Financial Reporting Standards*. In response to the AcSB allowing rate-regulated entities the option to delay their adoption of IFRS to January 1, 2012, the OEB has adjusted certain policy statements in the report to account for this choice.

On November 17, 2010, the OEB initiated a working group to develop recommendations on how IFRS should be implemented together with IRM rate setting as well as issues that impact utilities under cost-of-service. We are actively participating in the working group.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We are continuously analyzing the impacts of changes on our disclosure controls and procedures and internal controls over financial reporting as we proceed through our implementation of IFRS. Additional disclosure controls may be required to address first-time adoption and additional internal controls may be required to implement changes in our accounting policies and to support our ongoing IFRS reporting requirements.

We have initiated the process of analyzing our current disclosure control and procedure and internal control documentation to identify changes required upon the adoption of IFRS. We have categorized each control process as low, medium or high-impact, based on the currently assessed risk of a major change being required upon implementation of IFRS. This ranking was completed in the fourth quarter of 2009. We completed updating the documentation for all of the low and medium-risk processes with IFRS implementation impact, including process documentation and risk and control matrices, during the second quarter of 2010. Completion of our documentation revisions for our high-risk processes had been put on hold pending an anticipated decision from the IASB on the allowance of rate-regulated accounting under IFRS due to the impact that would have had on these processes. We plan to initiate the completion of the revisions to our high-risk processes in the first quarter of 2011 now that there is certainty that RRA will not be permitted upon our adoption of IFRS. Once our high-risk process documentation has been updated, we will begin walkthroughs of all of our revised process and control documentation for low, medium and high-risk processes. At this time we estimate that we will complete this on a timely basis for reporting under IFRS in 2012.

Financial Reporting Expertise

The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a quarterly basis, or more often as necessary.

The training of key finance and operational staff commenced in 2007 and has been ongoing. Training has also been given to the Audit and Finance Committee and senior executive management to communicate the key differences between Canadian GAAP and IFRS, and to provide them with an overview of the key impacts conversion could have on our financial statements. These groups are updated as developments in IFRS continue. Due to the extensive staffing requirements associated with such a large-scale project, an external expert advisor was engaged to assist with our IFRS conversion project, from the planning phase through to implementation.

The Audit and Finance Committee and senior management continue to be updated for key developments in IFRS and their potential impact on our financial statements. Updates are provided on at least a quarterly basis. This will continue through to our conversion to IFRS in 2012. During the third quarter we continued to provide training to our key finance and operational staff. To date, they have been trained in many key areas including property, plant and equipment, regulatory accounting, revenue recognition, liabilities, employee benefits, financial instruments and most recently income taxes. In addition to sessions on specific topics, we have also held one financial reporting update session. During the next year, we will continue to provide IFRS financial reporting update sessions on a regular basis.

Business Activities

The Company has 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. Depending on the outcome of various exposure drafts under IFRS, we could undergo changes to our results that would impact our debt covenants. For example, covenants would be impacted as a result of de-recognition of regulatory assets and liabilities, accounting for expenditures related to employer-sponsored pension plans on an accrual basis versus a cash basis and the change in costs that are allowable versus disallowable for capitalization as part of the cost of self-constructed assets. As part of our IFRS transition project, we have been analyzing the impact of potential changes in accounting policy on our debt covenants and communicating potential scenarios and impacts analyses to our Audit and Finance Committee. Based on our current estimates, we would remain in compliance with our debt covenants. However, we met with our financial institutions and amended our credit agreement with the syndicate of banks to consider the potential impacts that IFRS may have on our covenants. Specifically, the calculation of our debt to total capitalization ratio was modified under this agreement for certain items to factor in IFRS impacts, such that the debt to total capitalization ratio is representative of what it was prior to IFRS. The same ratio is used to support the indenture agreement with our bondholders. Given our current estimates, the indenture agreement was not updated at that time because we anticipated that we would remain within the threshold for our debt to capitalization ratio given the information available at the time. We have continued to monitor the impact of conversion on our debt covenants as IFRS develops and as we finalize our policy choices under IFRS. With the recent deferral of the IASB RRA project, we intend to re-assess the impact on our debt to capitalization ratio and identify appropriate next steps.

Information Technology (IT) Systems

As part of an entity-wide system improvement project, many of our major financial systems were replaced in 2008 and 2009. To ensure that the future requirements of IFRS would be met, common team members were included within the governance structure of our IFRS project and the new entity-wide system implementation team. At the same time, members of the IFRS implementation team were involved in the design of our new entity-wide system. IT implications were identified and assessed during our diagnostic and design and planning stages of our IFRS project and were incorporated in the project's solution development stage. For example, the new system has been configured to track depreciation on a component level, based on the useful life of the asset, as currently required under IAS 16. The new system has also been configured to track allowable versus disallowable costs for capitalization under IAS 16. The system was designed with the maximum flexibility given the uncertainty of the outcome of certain impactive IASB projects at the time. When the AcSB deferred implementation of IFRS for rate-regulated entities, we began making the required changes to continue reporting under Canadian GAAP until January 1, 2012. We have substantially completed required changes to our systems in order to have them ready to report under IFRS beginning on January 1, 2012, with comparatives.

Environmental Reporting

We currently record environmental liabilities for the estimated future expenditures to comply with regulations that require us to remediate certain environmental issues. Specifically, we have obligations related to PCB-contaminated equipment, chemically-contaminated lands adjacent to certain of our properties, and buildings that have asbestos- containing materials. We also currently record an asset retirement obligation (ARO) for the removal and disposal of asbestos-containing materials from some of our buildings. These obligations are recorded based on the present value of the future estimated cash flows. Under Canadian GAAP this present value is calculated using a fixed discount rate which is the credit-adjusted risk-free rate at the date of recognition. When we transition to IFRS, we will be required to reassess this discount rate and, as it will no longer be fixed, we will be required to adjust it at each balance sheet date. The impact of this change on our recorded obligations cannot be predicted at this time as it will depend on future economic conditions.

Under Canadian GAAP, an ARO exists where there is a legal obligation to remove and dispose of an asset or remediate a contaminated site. Under IFRS an ARO also includes obligations that are not legal but which are constructive in nature. Such a constructive obligation may be inferred from other factors such as a reporting enterprise's policies, actions or public statements. Under IFRS, new constructive obligations will be recorded as AROs in cases where we expect that specific lands will no longer be used for operational purposes and where we expect to remove assets or remediate properties.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Consistent with transitioning our financial systems to an SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project, we successfully implemented various Finance, Human Resources, Payroll and Investment Management modules in 2009. The reporting tool Business Intelligence/Business Warehouse was also implemented. This implementation included new controls over Internal Controls over Financial Reporting (ICFR) and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

A Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of supply chain is expected to be completed in 2011. The resulting new processes are currently being reviewed to assess the impact on the control environment. Process documents will be updated and controls will be tested for design and operating effectiveness in 2011.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2010, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our Company is made known within our Company. Based on the evaluation of the design and operation of our DC&P, our certifying officers concluded that our DC&P was effective as at December 31, 2010. Further, our Certifying Officers have also certified that ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. Based on the evaluation of the design and operating effectiveness of the Company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2010.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2008, 2009 and 2010. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations

Year ended December 31 (Canadian dollars in millions, except earnings per common share)	**2010**	2009	2008
Revenues	**5,124**	4,744	4,597
Net income	**591**	470	498
Basic and fully diluted earnings per common share	**5,727**	4,528	4,797

Consolidated Balance Sheets

Year ended December 31 (Canadian dollars in millions, except cash dividends per share)	**2010**	2009	2008
Total assets	**17,322**	15,635	13,878
Total long-term debt	**7,778**	6,881	6,133
Cash dividends per common share	**100**	1,700	2,410
Cash dividends per preferred share	**1.375**	1.375	1.375

OUTLOOK

To achieve our vision to be the leading electricity delivery company in North America, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, innovation and connecting renewable energy, reliability, protection of the environment, recruitment and knowledge retention, shareholder value and productivity. We work in an environment where safety is of the utmost importance. Our people underpin everything we do, and as such, we remain resolute in our commitment to safety. We will continue to focus our efforts to improve our customers' satisfaction by maintaining operational excellence through our efforts to innovate and to renew transmission and distribution systems. In particular, we will focus on targeted investments to address overloaded or aging equipment at customer delivery points, power quality and network performance necessary to improve reliability, which will in turn improve customer satisfaction. We will also continue to assist customers in understanding and managing the impacts of building a clean energy future.

The LTEP continues the energy strategies set out in the GEA introduced in 2009. The need to rapidly reduce the energy sector's carbon footprint dominates current environmental decision-making, leading to high expectation for immediate action and expansion of clean energy supply. Emerging technologies and the need to connect clean and renewable generation challenges our Transmission and Distribution Businesses to recalibrate and establish a more flexible and smart electricity grid.

We are planning significant investments in transmission and distribution infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability in the public interest. Our investment plan supports the achievement of the Province's phase-out of coal-fired generation, 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 2010, the OEB approved our 2011 distribution rates with a revenue requirement of approximately $1,218 million. The revenue requirement approved was lower than requested, but should continue to support our work programs necessary to sustain our critical infrastructure, increase reliability through enhanced forestry management, support the smart meter requirements and invest in a sustainable electricity system that supports renewable generation. We will monitor and address any associated risks should they arise. We will be preparing evidence to support a potential distribution rate application for the years 2012 and 2013.

In early 2011, the OEB approved our 2011 and 2012 transmission rates, with revenue requirements of approximately $1,346 million and $1,658 million, respectively. The approved revenue requirements will continue to support aging critical infrastructure, area supply projects and the Province's policy objectives. The 2012 revenue requirement includes the OEB's direction to adopt IFRS accounting for indirect overheads capitalized resulting in a $200 million shift between capital expenditures and operating expenses.

The actual timing and expenditures in our plan are predicated on obtaining various approvals including OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Further, we have made assumptions in the plan regarding cost responsibility and funding, consistent with the GEA regulations and amended TSC and DSC.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and ensuring that environmental factors are considered in making our business decisions. Our commitment to the environment has been recognized by Canada's Energy, Environment and Excellence group and Corporate Knights magazine.

Key enablers of the successful implementation of our work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our association 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, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2009, the Government announced its intention to make the exemption from the electricity transfer tax permanent for transfers of electricity assets within the public sector. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. The investment plan does not include any funding for any LDC acquisitions or divestitures.

We will continue to increase enterprise value through productivity improvements and cost-effectiveness driven by technology. Over the last two years, we have replaced most of our core systems with an enterprise-wide information technology system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. In addition, significant opportunity resides with smart meters and the proliferation of a smart grid, including energy efficiency, demand response and distributed-resources technologies.

Through the outlook period, we anticipate no changes to our role within the industry and expect that our financial returns will be sufficient to maintain our credit quality.

APPOINTMENT OF JANET HOLDER

On July 1, 2010, Janet Holder was appointed to our Board of Directors. Ms. Holder is the President of Enbridge Gas Distribution and serves on the Board of Governors at the University of New Brunswick.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, 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 and our performance measures and targets; statements related to the IPSP; statements about smart meters including their capabilities, their timing of installation and our focus on building an advanced distribution solution that will leverage our smart meter investment; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of changes to codes, licences, rules, new regulatory guidelines, tariff rate changes, cost recovery, return on equity, rate structures, revenue requirements and impacts on an average customer's total bill; expectations regarding the timing and content of applications to, hearings with and decisions from the OEB and other regulatory bodies; statements related to the LTEP; expectations regarding the OEB's Framework for Transmission Project Development Plans; statements about outstanding legal proceedings; statements regarding time-of-use billing; expectations regarding future renewable energy generation; statements regarding our liquidity and capital resources and their use; expectations regarding our financing activities, including our capital management objectives and our ability to access the capital markets; expectations about our maturing debt and interest payments; expectations regarding the results of our ongoing and planned projects and/or initiatives and their completion dates; statements regarding expected future capital expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commitments; statements regarding the effect of load on our revenue including the anticipated impact of CDM programs; the effect of interest rates on our revenue requirements and results of operations; statements regarding the estimated impact of changes in the forecasted long-term Government of Canada bond yield on our results of operations; impacts to our business in respect of the adequacy and timing of supply of materials, supplies and services and credit risk of our counterparties; expectations regarding future pension contributions, effect of health care cost trend on the future benefits costs and the performance of our pension plan; the possibility of the Province making declarations pursuant to our memorandum of agreement with them; statements regarding possible future actions of the Province and regulatory bodies; expectations regarding connections of new generation to our transmission and distribution systems; expectations regarding asset condition; statements regarding workforce demographics and the market for skilled labour; statements regarding the amount and timing of future estimated environmental expenditures, including with respect to LAR and PCBs; statements about future asbestos removal expenditures and asset retirement obligations; expectations regarding our information technology strategy and enterprise reporting system; the possibility that we could in future decide to issue foreign currency-denominated debt; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements about our outsourcing arrangement with Inergi LP; statements regarding provincial ownership of our transmission corridors; statements about critical accounting estimates; statements about IFRS, our conversion to IFRS and the effect of the absence of rate-regulated accounting under IFRS; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, our credit rating and credit quality and structural changes to our Company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," "goal," "aim," "target," 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 delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission Businesses; a stable regulatory environment; the preparation of business plans, regulatory filings and future capital expenditures on the basis that commencing 2011 rate-regulated accounting will not be permitted under IFRS; no unfavourable changes in environmental regulation; 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 sources. 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 impact of the GEA and the LTEP, including unexpected expenditures arising therefrom;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, cost recovery and rates, as well as changes to rules under various regulatory body review;
- the potential impact of CDM programs on our load and our revenues;
- unanticipated changes in electricity demand or in our 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 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 that we may not recover all of our project costs to prepare a bid associated with the OEB's Framework for Transmission Project Development Plans;
- the risk that we will be unable to source the materials necessary to support our work programs;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risk of currently undetermined future asbestos removal costs;
- 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 risks associated with information system security and 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;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks associated with changes in interest rates;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- 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; and
- the impact of the final outcome of the exposure draft on rate-regulated accounting under IFRS.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this Management's Discussion and Analysis (MD&A). You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at February 10, 2011. 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 10, 2011.

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 National Instrument 52-109 (Bill 198). An internal audit function evaluates the effectiveness of these internal controls consistent with its annual audit plan and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG 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 Independent Auditors' Report, which appears on page 43, 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 Executive Vice-President 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 and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer

Sandy Struthers
Executive Vice-President and Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009, the consolidated statements of operations and comprehensive income, retained earnings and accumulated other comprehensive income, and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Hydro One Inc. as at December 31, 2010 and December 31, 2009, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 10, 2011

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in millions, except per share amounts)	**2010**	2009
Revenues		
Transmission *(Note 16)*	**1,307**	1,147
Distribution *(Note 16)*	**3,754**	3,534
Other	**63**	63
	5,124	4,744
Costs		
Purchased power *(Note 16)*	**2,474**	2,326
Operation, maintenance and administration *(Note 16)*	**1,078**	1,057
Depreciation and amortization *(Note 3)*	**583**	537
	4,135	3,920
Income before financing charges and provision for payments in lieu of corporate income taxes	**989**	824
Financing charges *(Note 4)*	**342**	308
Income before provision for payments in lieu of corporate income taxes	**647**	516
Provision for payments in lieu of corporate income taxes *(Notes 5 and 16)*	**56**	46
Net income	**591**	470
Other comprehensive income	**-**	-
Comprehensive income	**591**	470
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 15)*	**5,727**	4,528

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2010**	2009
Retained earnings, January 1	**1,791**	1,497
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	**-**	12
Net income	**591**	470
Dividends *(Note 15)*	**(28)**	(188)
Retained earnings, December 31	**2,354**	1,791

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in millions)	**2010**	2009
Accumulated other comprehensive income, January 1	**(10)**	(10)
Other comprehensive income	**-**	-
Accumulated other comprehensive income, December 31	**(10)**	(10)

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2010**	2009
Assets		
Current assets:		
Cash	**33**	-
Short-term investments *(Note 17)*	**139**	-
Accounts receivable (net of allowance for doubtful accounts - $25 million; 2009 - $25 million) *(Note 16)*	**911**	843
Regulatory assets *(Note 8)*	**42**	72
Materials and supplies	**21**	21
Future income tax assets *(Note 5)*	**35**	21
Other	**8**	16
	1,189	973
Fixed assets *(Note 6)*:		
Fixed assets in service	**19,767**	18,407
Less: Accumulated depreciation	**7,247**	6,815
	12,520	11,592
Construction in progress	**1,402**	1,256
Future use land, components and spares	**139**	150
	14,061	12,998
Other long-term assets:		
Regulatory assets *(Notes 8 and 22)*	**1,013**	858
Deferred pension asset *(Note 12)*	**460**	424
Long-term investment *(Note 9)*	**249**	-
Intangible assets (net of accumulated amortization) *(Notes 2 and 7)*	**189**	218
Goodwill	**133**	133
Future income tax assets *(Notes 2 and 5)*	**19**	18
Other	**9**	13
	2,072	1,664
Total assets	**17,322**	15,635

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2010**	2009
Liabilities		
Current liabilities:		
Bank indebtedness	**-**	26
Accounts payable and accrued charges *(Notes 13 and 16)*	**884**	800
Regulatory liabilities *(Note 8)*	**72**	100
Accrued interest	**84**	74
Short-term notes payable	**-**	55
Long-term debt payable within one year *(Note 9)*	**500**	600
	1,540	1,655
Long-term debt *(Note 9)*	**7,278**	6,281
Other long-term liabilities:		
Employee future benefits other than pension *(Note 12)*	**980**	940
Regulatory liabilities *(Notes 8 and 22)*	**540**	489
Future income tax liabilities *(Notes 5 and 22)*	**693**	533
Environmental liabilities *(Note 13)*	**287**	303
Asset retirement obligations *(Note 14)*	**11**	-
Long-term accounts payable and other liabilities	**12**	16
	2,523	2,281
Total liabilities	**11,341**	10,217
Contingencies and commitments *(Notes 18 and 19)*		
Shareholder's equity *(Note 15)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**2,354**	1,791
Accumulated other comprehensive income	**(10)**	(10)
Total shareholder's equity	**5,981**	5,418
Total liabilities and shareholder's equity	**17,322**	15,635

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2010**	2009
Operating activities		
Net income	**591**	470
Environmental expenditures	**(17)**	(9)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	**526**	487
Regulatory asset and liability accounts	**(10)**	(34)
Future income taxes	**(8)**	16
Asset retirement obligation	**4**	-
Other	**1**	-
	1,087	930
Changes in non-cash balances related to operations *(Note 17)*	**77**	(38)
Net cash from operating activities	**1,164**	892
Financing activities		
Long-term debt issued	**1,500**	1,150
Long-term debt retired	**(600)**	(400)
Short-term notes payable	**(55)**	55
Dividends paid	**(28)**	(188)
Other	**-**	2
Net cash from financing activities	**817**	619
Investing activities		
Capital expenditures		
Fixed assets	**(1,557)**	(1,473)
Intangible assets	**(13)**	(93)
	(1,570)	(1,566)
Long-term investments	**(250)**	-
Other assets	**37**	13
Net cash used in investing activities	**(1,783)**	(1,553)
Net change in cash and cash equivalents	**198**	(42)
Cash and cash equivalents, January 1	**(26)**	16
Cash and cash equivalents, December 31 *(Note 17)*	**172**	(26)

See accompanying notes to Consolidated Financial Statements.

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 Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Lake Erie Link Management Inc. and Hydro One Lake Erie Link Company Inc.

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.

Transmission

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. As part of that decision the OEB approved the disposition of export and wheeling fees liability and the transmission market-ready regulatory asset, which was factored into rates and refunded to customers over the four-year period ending December 31, 2010.

On May 30, 2008, Hydro One Networks submitted an application to the OEB to adjust Uniform Transmission Rates (UTRs) effective January 1, 2009. On August 28, 2008, the OEB approved the application allowing Hydro One Networks to recover revenues consistent with the OEB-approved 2008 revenue requirement which reflected the full repayment to customers of the amounts recorded in the Earnings Sharing Mechanism and the Revenue Difference Deferral Account at the end of 2008.

To achieve the necessary funding in support of required infrastructure, Hydro One Networks filed a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirements of approximately $1,233 million and $1,341 million, based on a return on equity of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision in respect of this application. The decision, which was effective July 1, 2009, resulted in reduced revenue requirements of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved return on equity. The OEB decision disallowed development capital expenditures of $180 million for 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, Hydro One Networks filed the additional evidence on two projects amounting to approximately $160 million in capital expenditures. The OEB approved the supplemental evidence for inclusion in Hydro One Networks' 2010 rates. This resulted in a revised revenue requirement of $1,257 million for 2010, on the basis of an updated return on equity of 8.39% for 2010.

On May 19, 2010 Hydro One Networks submitted an application for 2011 and 2012 transmission rates in continued support of its aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the Green Energy Act (GEA). This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012.

On December 23, 2010, the OEB issued its decision effective January 1, 2011 which resulted in revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The change in our 2012 revenue requirement resulted in a higher revenue requirement than originally submitted due to the OEB directing Hydro One to adopt IFRS accounting for overheads capitalized resulting in a $200 million increase in 2012.

Distribution

On December 18, 2008, the OEB issued a decision approving substantially all work program expenditures effective May 1, 2008, for implementation on February 1, 2009. The OEB also approved recovery of our smart meter expenditures made prior to the end of 2007. The decision approved the establishment of the revenue recovery account (Rider 4) to record the revenue differential between existing distribution rates and new rates. Rider 4 is being recovered over a 27-month period commencing February 1, 2009 and ending April 30, 2011.

In late 2008, Hydro One Networks filed an incentive regulation application for 2009 rates, with an update filed in January 2009, to reflect the impact of the 2008 distribution rate decision. The application was filed on the basis of the OEB's third-generation Incentive Regulation Mechanism (IRM) process, which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision approving the basic IRM increase and the $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009.

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates reflecting the Company's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. The application sought OEB approval of revenue requirements of approximately $1,150 million and $1,264 million for 2010 and 2011, respectively.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters. The OEB also approved certain distribution-related deferral account balances sought by Hydro One Networks in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011.

On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's second-generation IRM policy which incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 19, 2008, the OEB released its decision. The revised rates, including an amount of 67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008.

On November 7, 2008, Hydro One Brampton filed an application on the same basis for 2009 distribution rates. On March 13, 2009, the OEB released it decision and approved the submission on the basis of its second-generation IRM policy. The revised rates, including an amount of $1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009.

On November 6, 2009, Hydro One Brampton filed an application for 2010 distribution rates on the basis of the OEB's second-generation IRM process. On April 13, 2010, the OEB released its decision regarding this rate application approving our submission on the basis of the OEB's cost-of-capital and second-generation IRM policies. The revised rates had an implementation date of May 1, 2010.

On August 29, 2008, Hydro One Remote Communities filed a 2009 cost-of-service rate application proposing an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all work program expenditures effective May 1, 2009.

On November 4, 2009, Hydro One Remote Communities filed an application for 2010 distribution rates under the OEB's third-generation IRM, seeking approval of an increase to basic rates for the distribution and generation of electricity effective May 1, 2010. The increase reflects the standard inflationary adjustments incorporated in the third-generation IRM applications. On April 14, 2010, the OEB issued a decision regarding this rate application under the OEB's third-generation IRM policies. The revised rates were approved for implementation on May 1, 2010.

Regulatory Accounting

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, 2010 amounted to $493 million (2009 - $434 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 *Taxation Act, 2007* (Ontario) (*Corporations Tax Act* (Ontario), prior to 2009) as modified by the *Electricity Act, 1998*, and related regulations.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* and CICA Handbook Section 1100, *Generally Accepted Accounting Principles*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009. Adjustments to retained earnings were recorded on January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the Statement of Operations and Comprehensive Income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that they will be recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Materials and Supplies

Materials and supplies represent consumables, 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, 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; major components and spare parts; and capitalized development costs associated with deferred capital projects.

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 other minor fixed assets.

Easements
Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to land access rights.

Intangible Assets
Intangible assets represent computer applications software and other assets. These assets are capitalized at cost, which comprises materials, purchased software, labour and consulting, engineering, overheads and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses.

Construction and Development in Progress
Overhead costs, including shared corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on rate-regulated fixed assets under construction and intangible assets under development, based on the OEB's approved allowance for funds used during construction (2010 – 4.34%; 2009 – 5.89%).

Depreciation and Amortization
The capital costs of fixed assets and intangible assets, primarily consisting of applications software, are depreciated or amortized on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external review of its fixed asset and intangible asset depreciation and amortization rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation and amortization rates for the various classes of assets is included below:

	Depreciation and amortization rates (%)	
	Range	Average
Transmission	1% - 3%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	9%

The costs of intangible assets are primarily included within the administration and service classification above and these assets are amortized on a straight-line basis. Amortization rates for computer applications software and other intangible assets range from 9% to 11%.

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 fixed assets that are normally retired is charged to accumulated depreciation or amortization, with no gain or loss reflected in current 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 or amortization expense. Depreciation expense also includes the costs incurred to remove fixed assets where no asset retirement obligation has been recorded.

The estimated service lives of fixed or intangible 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 electricity 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

Comprehensive Income

Comprehensive income is comprised 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 to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the hedged debt.

Financial Assets and Liabilities

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:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Short-term investments	Held-to-maturity/Held-for-trading
Long-term investment	Held-to-maturity/Held-for-trading
Fixed-to-floating interest rate swaps	Not classified
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Accounts payable	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (unless otherwise specified)	Other liabilities
MTN Series 14 Note	Not classified
$500 million of MTN Series 19 Note	Not classified

Short-term investments are generally classified as held-to-maturity; however, certain short-term investments are classified as held-for-trading when the Company has no intent to hold a pool of assets to their maturity. Documentation of the short-term investment classification is made on inception.

Where long-term debt is designated as part of a hedging relationship, as in the case of the MTN Series 14 Note and $500 million of the MTN Series 19 Note, the long-term debt, and related hedging instrument, are not classified.

All financial instrument transactions are recorded at trade date.

Derivative Instruments 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 or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. 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 gain or loss related to the ineffective portion, if any, is recorded in financing charges.

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 formally documents the hedging relationship between the hedged item and the hedging instrument, its risk management objective for establishing the hedging relationship, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items.

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.

Financial Instrument Disclosures
The fair market value of the Company's long-term debt is determined using the fair value hierarchy levels disclosed in Note 10.

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 records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyls (PCBs) contaminated mineral oil removed from electrical equipment, based on the 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 recorded to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Asset Retirement Obligations

When required by force of law or regulation, Hydro One records an asset retirement obligation based on the present value of the estimated fair value expenditures to remove certain assets and mitigate related sites. Where the Company anticipates that the related expenditures will be recoverable in future rates, a corresponding amount is capitalized as a cost of the related fixed assets. 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 facilities in perpetuity, no asset retirement obligation currently exists. If, at some future date, a particular facility is shown not to meet the perpetuity criterion, it will be reviewed to determine whether a measurable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

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.

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The Company continues to assess the impact of conversion to IFRS on its results of operations.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2010**	2009
Depreciation of fixed assets in service	**456**	418
Amortization of intangible assets	**43**	36
Fixed asset removal costs	**57**	50
Amortization of regulatory and other assets	**27**	33
	583	537

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2010**	2009
Interest on long-term debt payable	**409**	369
Less: Interest capitalized on construction and development in progress	**(54)**	(58)
Interest earned on investments	**(3)**	(1)
Other	**(10)**	(2)
	342	308

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. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in millions)	**2010**	2009
Income before provision for PILs	**647**	516
Federal and Ontario statutory income tax rate	**31.00%**	33.00%
Provision for PILs at statutory rate	**201**	170

Increase (decrease) resulting from:
Net temporary differences included in amounts charged to customers:

Capital cost allowance in excess of depreciation and amortization	**(82)**	(74)
Retail settlement variance accounts	**-**	4
Pension contributions in excess of pension expense	**(18)**	(15)
Overheads capitalized for accounting but deducted for tax purposes	**(13)**	(14)
Interest capitalized for accounting but deducted for tax purposes	**(17)**	(19)
Employee future benefits other than pension expense in excess of cash payments	**3**	1
Environmental expenditures	**(5)**	(3)
Other	**(15)**	(6)
Net temporary differences	**(147)**	(126)
Net permanent differences	**2**	2
Total income tax provision for PILs	**56**	46
Current income tax provision for PILs	**64**	30
Future income tax provision for PILs	**(8)**	16
Total income tax provision for PILs	**56**	46
Effective income tax rate	**8.66%**	8.91%

The provision for payments in lieu of current income taxes of $64 million represents the amount payable to the OEFC with respect to current year earnings. The outstanding balance due to the OEFC at December 31, 2010 is $17 million (2009 - $6 million recoverable).

The payments in lieu of future income taxes recoverable of $8 million reflects the decrease in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Company's customers through future rates. The decrease in the liability for payments in lieu of future income taxes that is expected to be recovered from the Company's customers through future rates has resulted in a decrease in regulatory assets.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in millions)	**2010**	2009
Future income tax assets		
Depreciation and amortization in excess of capital cost allowance	**9**	6
Employee future benefits other than pension expense in excess of cash payments	**5**	4
Retail settlement variance accounts	**-**	3
Environmental expenditures	**3**	3
Other	**5**	3
Total future income tax assets	**22**	19
Less: current portion	**3**	1
	19	18

December 31 (Canadian dollars in millions)	**2010**	2009
Future income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	**(1,004)**	(825)
Employee future benefits other than pension expense in excess of cash payments	**337**	314
Environmental expenditures	**76**	82
Transmission and Distribution amounts received but not recognized for accounting purposes	**(69)**	(68)
Goodwill	**(17)**	(18)
Retail settlement variance accounts	**5**	5
Other	**11**	(3)
Total future income tax liabilities	**(661)**	(513)
Less: current portion	**32**	20
	(693)	(533)

As at December 31, 2010, payments in lieu of future income tax assets of $574 thousand (2009 – $461 thousand), based on substantively enacted income tax rates and laws, have not been recorded, as it is more likely than not that the assets will not be realized in the future.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets	Accumulated Depreciation	Construction in Progress	Total
2010				
Transmission	**10,204**	**3,626**	**1,070**	**7,648**
Distribution	**7,230**	**2,556**	**262**	**4,936**
Communication	**892**	**426**	**37**	**503**
Administration and service	**1,089**	**554**	**33**	**568**
Easements	**491**	**85**	**-**	**406**
	19,906	**7,247**	**1,402**	**14,061**
2009				
Transmission	9,485	3,455	956	6,986
Distribution	6,773	2,392	220	4,601
Communication	806	376	54	484
Administration and service	1,007	510	26	523
Easements	486	82	-	404
	18,557	6,815	1,256	12,998

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 $54 million in 2010 (2009 - $55 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2010				
Computer applications software	**395**	**209**	**1**	**187**
Other assets	**5**	**3**	**-**	**2**
	400	**212**	**1**	**189**
2009				
Computer applications software	379	166	3	216
Other assets	5	3	-	2
	384	169	3	218

Financing costs are capitalized on intangible assets under development, including allowance for funds used during construction on regulated assets, and were $nil in 2010 (2009 - $3 million).

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:

December 31 (Canadian dollars in millions)	**2010**	2009
Regulatory assets:		
Regulatory future income tax asset	**674**	523
Environmental	**309**	327
Pension cost variance account	**27**	7
Rider 2 (Regulatory asset recovery account II)	**11**	19
Rural and remote rate protection variance account	**7**	24
Long-term project development cost account	**7**	2
Rider 4 (Revenue Recovery Account)	**5**	18
Other	**15**	10
Total regulatory assets	**1,055**	930
Less: current portion	**42**	72
	1,013	858

	2010	2009
Regulatory liabilities:		
Deferred pension	**460**	424
External revenue variance account	**29**	12
Regulatory future income tax liability	**30**	32
Retail settlement variance accounts	**22**	-
Rider 3 (regulatory liability refund account)	**19**	49
Rider 6	**19**	31
Rider 8	**9**	-
Hydro One Brampton rider	**6**	9
Export and wheeling fees	**3**	15
Other	**15**	17
Total regulatory liabilities	**612**	589
Less: current portion	**72**	100
	540	489

Regulatory Assets

Regulatory Future Income Tax Asset and Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs would have been higher by approximately $104 million (2009 - $127 million) including the impact of a change in substantively enacted tax rates.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2010, this regulatory asset decreased by $15 million (2009 – increased by $30 million) to reflect related changes in the Company's PCB liability and decreased by $1 million (2009 – increased by $40 million) for a change in the land assessment and remediation (LAR) liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $16 million (2009 - higher by $70 million). In addition, amortization expense in 2010 would have been lower by $17 million (2009 - $9 million) and financing charges would have been higher by $15 million (2009 - $13 million).

Pension Cost Variance Account

The pension cost variance account was established for Hydro One Networks' Transmission and Distribution Businesses to track the difference between the actual pension costs incurred by the Company and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid compared to OEB-approved amounts. On May 28, 2009, the OEB announced its decision regarding the Company's rate application in respect of the Transmission Business of Hydro One Networks for 2009 and 2010 rates. As part of this decision, the OEB approved recovery of the proposed balance in this account plus accrued interest for recovery over 18 months ending December 31, 2010. In the December 23, 2010 decision on 2011 and 2012 transmission rates, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, revenue would have been lower by $20 million in 2010 (2009 - $7 million).

Rider 2 or 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 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 2010 would have been lower by $8 million (2009 - $23 million). In addition, related financing charges would have remained the same in both years.

Rural and Remote Rate Protection Variance Account (RRRP)

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. In 2002, the OEB approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account to be disposed of at a later date.

Long-term Project Development Cost Account

On May 28, 2009 the OEB approved the creation of a deferral account to record Hydro One's costs of preliminary work to advance certain transmission projects identified in its 2009 and 2010 transmission rate application. On March 25, 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 21, 2009 request from the Government of Ontario. In its December 23, 2010 decision, the OEB approved the recovery of the December 31, 2009 balance, including accrued interest, over a one-year period from January 1, 2010 to December 31, 2011. The Company anticipates that it will seek recovery for the remaining balance in its next transmission rate application. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been higher by $5 million (2009 - $2 million).

Rider 4 or Revenue Recovery Account

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. The approved rates were effective May 1, 2008 with an implementation date of February 1, 2009. The OEB approved the establishment of Rider 4 to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through a rate rider, over a period of 27 months commencing February 1, 2009 and ending April 30, 2011.

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 lower by $22 million (2009 - higher by $9 million).

External Revenue Variance Account

In its May 28, 2009 decision, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use and external revenue from station maintenance and engineering and construction work. These revenue sources are an offset to the Company's revenue requirement, and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecast and actual revenues from these sources of external revenue. The balance reflects the excess of external revenue compared to the OEB-approved forecast. The OEB's December 23, 2010 decision approved the disposition of the December 31, 2009 balance, including accrued interest, over a one-year period from January 1, 2010 to December 31, 2011.

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 18, 2008 decision allowed for the disposition of RSVA accumulated since May 1, 2006 through to April 30, 2008, inclusive of interest, within the Regulatory Liability Refund Account (RLRA). Hydro One Networks accumulated a net liability in its RSVA from May 1, 2008 to December 31, 2009. On April 9, 2010, the OEB announced its decision regarding Hydro One Networks' distribution rate application which included the allowance to dispose of the RSVA accumulated during that period, inclusive of interest, within Rider 6. Hydro One Networks has accumulated a net liability in its RSVA account since December 31, 2009.

RLRA

The OEB's December 18, 2008 decision approved certain distribution-related deferral account balances sought by Hydro One in its application including RSVA amounts, deferred tax changes, OEB costs and smart meters. Amounts approved for recovery represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011.

Rider 6

As part of the April 9, 2010 decision, the OEB approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over an 18-month period from May 1, 2010 to December 31, 2011.

Rider 8

As part of the April 9, 2010 decision, the OEB also requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received.

Hydro One Brampton Rider

On April 13, 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVA, sought by Hydro One Brampton in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account to be disposed of over a two-year period from May 1, 2010 to April 30, 2012.

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 Networks' Transmission Business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 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 and wheeling fees. The export and wheeling fees were factored into rates over a four-year period ending December 31, 2010.

9. DEBT

December 31 (Canadian dollars in millions)	**2010**	2009
Long-term debt:		
7.15% debentures due 2010	-	400
3.89% notes due 2010	-	200
4.08% notes due 2011 [1]	**250**	250
6.40% notes due 2011	**250**	250
5.77% notes due 2012	**600**	600
5.00% notes due 2013	**600**	600
3.13% notes due 2014 [1]	**750**	250
2.95% notes due 2015	**250**	-
4.64% notes due 2016	**450**	450
5.18% notes due 2017	**600**	600
4.40% notes due 2020	**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**	400
6.03% notes due 2039	**300**	300
5.49% notes due 2040	**500**	300
6.59% notes due 2043	**315**	315
5.00% notes due 2046	**325**	75
	7,775	6,875
Add: Unrealized hedged loss [1]	**8**	11
Less: Long-term debt payable within one year	**(500)**	(600)
Net unamortized premiums	**27**	24
Unamortized debt issuance costs	**(32)**	(29)
Long-term debt	**7,278**	6,281

[1] The unrealized hedged loss relates to the MTN Series 14 Note, and $500 million of the MTN Series 19 Note issued in January of 2010, which are accounted for as fair value hedges. The unrealized hedged loss is offset by the $8 million (2009 - $11 million) unrealized gain on the related fixed-to-floating interest rate swap agreements.

Short-term debt represents promissory notes pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2010, the notes had a weighted average interest rate of 0.05%.

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks maturing in June 2013. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program. In addition, the Company holds $250 million of Province of Ontario Floating Rate Notes.

The Company issues notes for long-term financing under the Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million, of which $1,250 million was remaining and available as at December 31, 2010.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in Note 10.

10. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying value of financial instruments as at December 31, 2010 is as follows:

(Canadian dollars in millions)	Derivatives Used for Hedging	Other Financial Instruments Used for Hedging	Held-for-Trading	Loans and Receivables	Other Financial Liabilities
Financial Assets					
Cash	-	-	33	-	-
Accounts receivable	-	-	-	911	-
Short-term investments	-	-	139	-	-
Long-term investment	-	-	249	-	-
Other assets	8	-	-	1	-
Financial Liabilities					
Accounts payable and accrued charges[1]	-	-	-	-	861
Long-term debt	-	758	-	-	7,020

[1] Accounts payable and accrued charges do not include income taxes payable or dividends payable.

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, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in millions)	**2010**		2009	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**7,775**	**8,555**	6,875	7,302

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the MTN Series 14 Note and $500 million of the MTN Series 19 Note, which are designated as part of hedging relationships.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency denominated debt which would be hedged back to Canadian dollars consistent with Hydro One's risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution and Transmission Businesses is derived using a formulaic approach which is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce its Transmission Business' results of operations by approximately $16 million and its Distribution Business' results of operations by approximately $10 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2010, 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 individual customer. As at December 31, 2010, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts remained unchanged at $25 million (2009 - $25 million). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2010, approximately 3% of the Company's accounts receivable were aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques including entering into transactions with highly-rated counter-parties; limiting total exposure levels with individual counter-parties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counter-parties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest rate risk. 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. No such agreements were outstanding as at December 31, 2010.

Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at December 31, 2010, the derivative instruments held by Hydro One include a $250 million fixed-to-floating interest rate swap agreement to convert the 4.08% coupon note maturing March 3, 2011 into a three-month variable rate debt and two $250 million fixed-to-floating interest rate swap agreements to convert $500 million of the 3.13% coupon note maturing November 19, 2014 into a three-month variable rate debt. The counter-party credit risk exposure on the fair value of the three interest rate swap contracts is $11 million as at December 31, 2010.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, the Company's Commercial Paper Program, under which it is authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holdings of Province of Ontario Floating Rate Notes. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks maturing June 1, 2013 and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

As at December 31, 2010, accounts payable and accrued charges in the amount of $861 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next twelve months is $500 million. Interest payments over the next 12 months on the Company's outstanding long-term debt amount to $405 million.

As at December 31, 2010, Hydro One has issued long-term debt in the amount of $7,775 million and the Company is required to make interest payments in the amount of $6,599 million. Principal outstanding, interest payments and related weighted average interest rates are 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)*	Interest Payments *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	500	405	5.2
2 years	600	383	5.8
3 years	600	349	5.0
4 years	750	319	3.1
5 years	250	295	3.0
	2,700	1,751	4.5
6 – 10 years	1,350	1,246	4.8
Over 10 years	3,725	3,602	6.0
	7,775	6,599	5.3

11. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, short-term notes payable, long-term debt and cash and cash equivalents. The Company's capital structure as at December 31, 2010 and December 31, 2009 was as follows:

(Canadian dollars in millions)	**2010**	2009
Short-term notes payable	**-**	55
Long-term debt payable within one year	**500**	600
Less: Cash and cash equivalents	**33**	(26)
	467	681
Long-term debt	**7,278**	6,281
Preferred Shares	**323**	323
Common Shares	**3,314**	3,314
Retained Earnings	**2,354**	1,791
	5,991	5,428
Total Capital	**13,736**	12,390

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2010, Hydro One is in compliance with all of these covenants and limitations.

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 Asset Mix

Hydro One's pension plan asset mix at December 31, 2010 and 2009 was as follows:

	% of Plan Assets	
December 31	**2010**	2009
Equity securities	**63.5**	63.3
Debt securities	**30.7**	32.9
Other	**5.8**	3.8
	100.0	100.0

Supplementary Information

The Hydro One pension plan holds $14 million of Hydro One Inc. corporate bonds (2009 - $9 million) and holds debt securities of the Province of $70 million at December 31, 2010 (2009 - $88 million).

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 with the Financial Services Commission of Ontario (FSCO) in September 2010, effective for December 31, 2009, the Company contributed $193 million to its pension plan in respect of 2010 (2009 - $112 million), $145 million of which is required to satisfy minimum funding requirements. The Company made an additional payment of $48 million in December 2010. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2010, 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 $233 million (2009 - $155 million).

Year ended December 31 (Canadian dollars in millions)	Pension **2010**	Pension 2009	Employee Future Benefits other than Pension **2010**	Employee Future Benefits other than Pension 2009
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**4,566**	4,007	**1,004**	874
Current service cost	**94**	73	**24**	19
Interest cost	**294**	286	**65**	63
Reciprocal transfers	**4**	-	**-**	-
Benefits paid	**(262)**	(270)	**(42)**	(43)
Net actuarial loss (gain)	**300**	470	**127**	91
Accrued benefit obligation, December 31	**4,996**	4,566	**1,178**	1,004
Change in plan assets				
Fair value of plan assets, January 1	**4,336**	3,836	**-**	-
Actual return on plan assets	**421**	642	**-**	-
Reciprocal transfers	**4**	6	**-**	-
Benefits paid	**(262)**	(270)	**-**	-
Employer's contributions[1]	**191**	112	**-**	-
Employees' contributions	**24**	21	**-**	-
Administrative expenses	**(15)**	(11)	**-**	-
Fair value of plan assets, December 31	**4,699**	4,336	**-**	-
Funded status				
Unfunded benefit obligation	**(297)**	(230)	**(1,178)**	(1,004)
Unamortized net actuarial losses (gains)	**746**	640	**144**	10
Unamortized past service costs	**11**	14	**11**	14
Deferred pension asset (accrued benefit liability)	**460**	424	**(1,023)**	(980)
Less: Current portion	**-**	-	**43**	40
Deferred pension asset (long-term liability)	**460**	424	**(980)**	(940)

[1] In January 2011, the Company made a contribution of $13 million in respect of 2010 (2010 - $10 million in respect of 2009).

	Pension		Employee Future Benefits Other Than Pension	
Year ended December 31 (Canadian dollars in millions)	**2010**	2009	**2010**	2009
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**70**	52	**24**	19
Interest cost	**294**	286	**65**	63
Actual return on plan assets net of expenses	**(406)**	(631)	**-**	-
Actuarial loss (gain)	**300**	470	**127**	91
Other	**(1)**	(1)	**-**	-
Costs arising in the period	**257**	176	**216**	173
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**129**	359	**-**	-
Actuarial (gain) loss	**(236)**	(410)	**(134)**	(101)
Plan amendments	**4**	4	**4**	4
Net periodic benefit cost	**154**	129	**86**	76
Charged to results of operations[2]	**134**	68	**51**	46
Effect of a 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**-**	-	**185**	141
Service cost and interest cost	**-**	-	**15**	13
Effect of a 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**-**	-	**(146)**	(113)
Service cost and interest cost	**-**	-	**(12)**	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**6.50%**	7.25%	**-**	-
Weighted average discount rate	**6.50%**	7.25%	**6.50%**	7.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.75%	**2.50%**	2.75%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Average remaining service life of employees *(years)*	**10**	10	**11**	11
Rate of increase in health care cost trend[3]	**-**	-	**4.81%**	4.81%
For accrued benefit obligation, December 31:				
Weighted average discount rate	**5.75%**	6.50%	**5.75%**	6.50%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Rate of increase in health care cost trend[4]	**-**	-	**4.86%**	4.81%

[2] The Company follows the cash basis of accounting. During 2010, pension costs of $191 million (2009 - $113 million) were attributed to labour, of which $134 million (2009 - $68 million) was charged to operations and $57 million (2009 - $45 million) was capitalized as part of the cost of fixed assets.

[3] 8.57% in 2010 grading down to 4.81% per annum in and after 2029 (2009 – 8.81% in 2009 grading down to 4.81% per annum in and after 2029).

[4] 8.31% in 2011 grading down to 4.86% per annum in and after 2029 (2009 – 8.57% in 2010 grading down to 4.81% per annum in and after 2029).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	Polychlorinated Biphenyls (PCB)	Land Assessment and Remediation (LAR)	Total
2010			
Opening balance, January 1	**262**	**65**	**327**
Interest accretion	**13**	**2**	**15**
Expenditures	**(9)**	**(8)**	**(17)**
Revaluation adjustment	**(15)**	**(1)**	**(16)**
Ending balance, December 31	**251**	**58**	**309**
Less: Current portion	**(15)**	**(7)**	**(22)**
	236	**51**	**287**
2009			
Opening balance, January 1	225	28	253
Interest accretion	12	1	13
Expenditures	(4)	(5)	(9)
Revaluation adjustment	29	41	70
Ending balance, December 31	262	65	327
Less: Current portion	(14)	(10)	(24)
	248	55	303

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2010 and in total thereafter are as follows: 2011 - $22 million; 2012 - $23 million; 2013 - $34 million; 2014 - $40 million; 2015 - $33 million and thereafter - $217 million. Of the total estimated future expenditures, $308 million relate to PCB (2009 - $320 million) and $61 million to LAR (2009 - $69 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands. The Company's recorded liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on criteria including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009. However, in 2009, Hydro One sought and received an extension until 2014 for the removal of PCBs from certain station equipment that could potentially be contaminated in excess of this threshold. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets that must be compliant by 2014. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retrofilling with replacement oil that is less than 2 ppm.

Management's best estimate of the total estimated future expenditures to comply with PCB regulations is about $308 million. These expenditures are expected to be incurred over the period from 2011 to 2025. As a result of its most recent cost estimate to comply with existing PCB regulations, the Company reduced its December 31, 2010 PCB liability by approximately $15 million compared to September 30, 2010.

LAR

As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Company reduced its December 31, 2010 liability by approximately $1 million compared to September 30, 2010. The Company's best estimate of the total future expenditures to complete its LAR program is about $61 million.

14. ASSET RETIREMENT OBLIGATIONS

Consistent with the Company's accounting policy for asset retirement obligations, Hydro One records a liability for the present value of the estimated future expenditures associated with the retirement of tangible long-lived assets that the Company is legally required to remove. A corresponding amount is recorded as an asset retirement cost that is capitalized as part of the carrying amount of the related fixed asset.

There are uncertainties in estimating future expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

Hydro One has recorded a liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The Company's liability is based on management's best estimate of the present value of the estimated future expenditures to comply with existing regulations. During the year, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The Company has recorded a $7 million liability in respect of this obligation as at December 31, 2010 based on the net present value of the Company's best estimate of the total future expenditures of $18 million to complete its asbestos removal activities.

Hydro One has also recorded a $4 million asset retirement obligation related to the decommissioning and removal of its switching station located at Ontario Power Generation's Abitibi Canyon Generating Station.

15. 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, maintenance of the deemed regulatory capital structure, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2010, preferred dividends in the amount of $18 million (2009 - $18 million) and common dividends in the amount of $10 million (2009 - $170 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.

16. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, Ontario Power Authority (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 2010 includes $1,277 million (2009 - $1,121 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2010 includes $127 million (2009 - $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 2010 includes $28 million (2009 - $31 million) related to these services.

In 2010, Hydro One purchased power in the amount of $2,361 million (2009 - $2,265 million) from the IESO administered electricity market, $19 million (2009 - $19 million) from OPG and $13 million (2009 - $11 million) from OEFC.

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 2010, Hydro One incurred $11 million (2009 - $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 $14 million (2009 - $13 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 $2 million in each of 2010 and 2009.

The OPA funds substantially all of our Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2010, Hydro One received $36 million from the OPA in respect of the CDM programs (2009 - $23 million) and had a net accounts receivable of $1 million in both 2010 and 2009.

The provision for payments in lieu of corporate income taxes, property taxes and capital 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)	**2010**	2009
Accounts receivable	**111**	108
Accounts payable and accrued charges	**(283)**	(254)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $222 million (2009 - $211 million).

17. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness." The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2010**	2009
Accounts receivable increase	**(68)**	(89)
Materials and supplies increase	**-**	(2)
Accounts payable and accrued charges increase	**87**	-
Accrued interest increase	**10**	10
Long-term accounts payable and other liabilities (decrease) increase	**(3)**	4
Employee future benefits other than pension increase	**40**	32
Other	**11**	7
	77	(38)

Supplementary information:

Interest paid	**409**	361
Payments in lieu of corporate income taxes	**48**	77

18. 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 will not have a material 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 Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and our Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The Red Rock First Nation Band commenced a similar claim on September 7, 2001 against the same parties. In 2004, the various claims were consolidated. These actions sought declaratory relief, injunctive relief and damages in an unspecified amount. The claims arose out of flooding activities of Ontario Hydro and the alleged effects of flooding on lands in which the two First Nations claim an interest. In May 2009, all parties entered into an agreement to dismiss all actions against Hydro One on a without costs basis. On July 27, 2010, by court order, the consolidated action and the cross claim of the Attorney General of Canada against Hydro One were dismissed without costs.

Transfer of Assets
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, 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 $761,500 that we paid to these Indian bands and bodies in 2010. If we cannot obtain consents from the Indian bands and bodies, 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 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 our net income if we are not able to recover them in future rate orders.

19. COMMITMENTS

Agreement with Inergi
Effective March 1, 2002, Inergi LP (Inergi) (a wholly owned subsidiary of Cap Gemini Canada Inc.) began providing services to Hydro One. On May 1, 2010, consistent with the terms of the contract, the Company extended the Master Services Agreement with Inergi for a further three-year period to expire on February 28, 2015. As a result of this agreement, Hydro One receives from Inergi a range of services including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Inergi billing for these services has ranged between $93 million and $130 million per year and is 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, 2010, and in total thereafter are as follows: 2011 - $143 million; 2012 - $139 million; 2013 - $135 million; 2014 - $130 million; 2015 - $22 million; and thereafter - $nil. The agreement expires on February 28, 2015.

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. As at December 31, 2010 and December 31, 2009, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton using only parental guarantees of $325 million. Prudential support at December 31, 2010 and December 31, 2009 was also provided on behalf of two distributors using guarantees of $660 thousand. The IESO could draw on these guarantees if these subsidiaries or distributors fail 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 corporate guarantee. 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.

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, 2010, Hydro One had bank letters of credit of $113 million (2009 - $107 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, 2010, and in total thereafter are as follows: 2011 - $5 million; 2012 - $8 million; 2013 - $6 million; 2014 - $7 million; 2015 - $2 million; and thereafter - $25 million.

20. 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, the operations of which primarily consist of those 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
2010				
Segment profit				
Revenues	**1,307**	**3,754**	**63**	**5,124**
Purchased power	**-**	**2,474**	**-**	**2,474**
Operation, maintenance and administration	**416**	**602**	**60**	**1,078**
Depreciation and amortization	**273**	**300**	**10**	**583**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**618**	**378**	**(7)**	**989**
Financing charges				**342**
Income before provision for payments in lieu of corporate income taxes				**647**
Capital expenditures	**936**	**629**	**5**	**1,570**

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2009				
Segment profit				
Revenues	1,147	3,534	63	4,744
Purchased power	-	2,326	-	2,326
Operation, maintenance and administration	438	564	55	1,057
Depreciation and amortization	240	287	10	537
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	469	357	(2)	824
Financing charges				308
Income before provision for payments in lieu of corporate income taxes				516
Capital expenditures	918	643	5	1,566

December 31 (Canadian dollars in millions)	**2010**	2009
Total assets		
Transmission	**9,805**	8,993
Distribution	**6,908**	6,481
Other	**609**	161
	17,322	15,635

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

21. SUBSEQUENT EVENTS

On February 2, 2011, the Power Workers' Union (PWU) requested that the Ministry of Labour appoint a Conciliation Officer to assist Hydro One and the PWU in finalizing a new collective agreement. Negotiations on the new agreement began on January 10, 2011.

On January 24, 2011, Hydro One issued notes under the Company's MTN Program. The issue consisted of $50 million floating-rate notes with a maturity date of July 24, 2015.

On January 19, 2011, Hydro One issued $250 million in notes under the Company's MTN Program. The issue has an additional offering of 2.95% notes maturing on September 11, 2015, originally issued on September 13, 2010. The total amount outstanding for this issue is now $500 million.

On January 19, 2011, Hydro One entered into two $125 million notional principal amount fixed-to-floating interest rate swaps to convert $250 million of Hydro One's 2.95% coupon note maturing September 11, 2015, into three-month variable rate debt.

On January 17, 2011, the PWU made an appeal to the Divisional Court of the Supreme Court of Canada under the *Ontario Energy Board Act, 1998* in regard to the OEB's December 23, 2010 decision approving Hydro One Networks' transmission rates for 2011 and 2012. The PWU submitted the appeal on the grounds that the decision failed to identify operations, maintenance and administration costs that the OEB considers imprudent and were therefore omitted in the calculation of the approved revenue requirement. The PWU is requesting that the OEB's determination regarding the revenue requirement and related rates be set aside and that the matter be remitted to a differently constituted panel of the OEB for a new hearing with respect to these issues. The appeal is not anticipated to impact upon the collection of the new 2011 transmission rates during the proceeding. The outcome of this appeal is not determinable at this time.

22. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2010 Consolidated Financial Statements.

In the third quarter, the Company changed the presentation of tax balances associated with certain temporary differences related to intangible assets and other regulatory account balances, to reflect how these balances will ultimately be settled. As a result, the Company reclassified the tax balances associated with these temporary differences, such that the amount of future income tax liabilities and the related net regulatory asset in the interim period balance sheet, and in the comparative December 31, 2009 balance sheet, have been reduced by $160 million. The change in presentation has no impact on revenue or operating cash flow.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	**2010**	2009	2008	2007	2006
Statement of operations data					
Revenues					
Transmission	**1,307**	1,147	1,212	1,242	1,245
Distribution	**3,754**	3,534	3,334	3,382	3,273
Other	**63**	63	51	31	27
	5,124	4,744	4,597	4,655	4,545
Costs					
Purchased power	**2,474**	2,326	2,181	2,240	2,221
Operation, maintenance and administration	**1,078**	1,057	965	995	880
Depreciation and amortization	**583**	537	548	521	515
	4,135	3,920	3,694	3,756	3,616
Income before financing charges and provision for payments in lieu of corporate income taxes	**989**	824	903	899	929
Financing charges	**342**	308	292	295	295
Income before provision for payments in lieu of corporate income taxes	**647**	516	611	604	634
Provision for payments in lieu of corporate income taxes	**56**	46	113	205	179
Net income	**591**	470	498	399	455
Basic and fully diluted earnings per common share *(Canadian dollars)*	**5,727**	4,528	4,797	3,809	4,366

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**9,805**	8,993	7,877	7,273	6,950
Distribution	**6,908**	6,481	5,873	5,407	5,161
Other	**609**	161	128	106	99
Total assets	**17,322**	15,635	13,878	12,786	12,210
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,540**	1,655	1,300	1,452	1,194
Long-term debt	**7,278**	6,281	5,733	5,063	4,848
Other long-term liabilities	**2,523**	2,281	1,721	1,385	1,347
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**2,354**	1,791	1,497	1,258	1,184
Accumulated other comprehensive income	**(10)**	(10)	(10)	(9)	-
Total liabilities and shareholder's equity	**17,322**	15,635	13,878	12,786	12,210

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	**2010**	2009	2008	2007	2006
Other financial data					
Capital expenditures					
Transmission	**936**	918	704	560	402
Distribution	**629**	643	570	511	417
Other	**5**	5	10	20	4
Total capital expenditures	**1,570**	1,566	1,284	1,091	823
Ratios					
Net asset coverage on long-term debt[1]	**1.77**	1.79	1.84	1.87	1.92
Earnings coverage ratio[2]	**2.39**	2.15	2.63	2.67	2.67
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	**142.2**	139.2	148.7	152.2	151.1
Ontario 20-minute system peak demand *(MW)*[3]	**25,145**	24,477	24,231	25,809	27,056
Ontario 60-minute system peak demand *(MW)*[3]	**25,075**	24,380	24,195	25,737	27,005
Total transmission lines *(circuit-kilometres)*	**28,951**	28,924	29,039	28,915	28,600
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	**29.1**	28.9	29.9	30.2	29.0
Units distributed through Hydro One lines *(TWh)*[3,4]	**42.5**	43.5	44.7	45.7	44.7
Total distribution lines *(circuit-kilometres)*	**123,552**	123,528	123,260	122,933	122,460
Customers	**1,345,177**	1,333,920	1,325,745	1,311,714	1,293,396
Total regular employees	**5,717**	5,427	5,032	4,602	4,295

[1] 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).

[2] 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.

[3] System-related statistics include preliminary figures for December.

[4] 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, 2010)

James Arnett[2]
Chair of the Board of Directors, Hydro One Inc.

Sami Bébawi[4]
President, Geracon Inc.

Advisor to the President, SNC-Lavalin Group Inc.

Kathryn A. Bouey[1,4,6]
President, TBG Strategic Services Inc.

Corporate Director

George Cooke[1,5,7]
President and CEO, The Dominion of Canada Insurance Company

Laura Formusa
President and Chief Executive Officer, Hydro One Inc.

Janet Holder[5,6,7]
President, Enbridge Gas Distribution Inc.

Don MacKinnon[5,6]
President, Power Workers' Union

Michael J. Mueller[1,2,4]
Corporate Director

Walter Murray[1,3,7]
Corporate Director

Robert L. Pace[2,3,7]
President and CEO, The Pace Group Ltd.

Gale Rubenstein[2,3,5]
Partner, Goodmans LLP

Douglas E. Speers[3,4,6]
Corporate Director

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 eleven times in 2010.

[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 eight times in 2010.

[3] *Human Resources Committee* The Human Resources Committee (Formerly 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. The committee met seven times in 2010.

[4] *Business Transformation 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 cornerstone project, the Smart Grid and Continuous Innovation Strategy, and the planning, development and implementation of major transmission system or distribution projects including projects described in the Corporation's Green Energy Implementation Plan. The committee met five times in 2010.

[5] *Regulatory and Public Policy Committee* The Regulatory and Public Policy Committee (Formerly the Regulatory and Environment Committee) monitors the Company's compliance with applicable regulatory requirements and legislation and is responsible for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on us. The committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The committee met seven times in 2010.

[6] *Health, Safety and Environment Committee* The Health, Safety and Environment Committee (Formerly the Health and Safety Committee) is responsible for reviewing occupational health, safety and environment policies, standards, and programs and compliance with occupational health, safety and environmental legislation, policies and standards, and public health and safety issues. The committee met five times in 2010.

[7] *Investment – Pension Committee* The Investment - Pension Committee's primary function is to assist the Board in fulfilling its oversight responsibilities in all matters related to the Corporation's Pension Plan including the Hydro One Pension Fund.

CORPORATE INFORMATION

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1-877-955-1155
www.HydroOne.com

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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 and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit

www.HydroOne.com.

REMOTES FINANCIAL STATEMENT

HISTORIC YEARS (2009, 2010 AND 2011)

Attachment 1: Hydro One Remote Communities Inc. Financial Statements 2009

Attachment 2: Hydro One Remote Communities Inc. Financial Statements 2010

Attachment 3: Hydro One Remote Communities Inc. Financial Statements 2011

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2009

HYDRO ONE REMOTE COMMUNITIES INC.
AUDITORS' REPORT

To the Shareholder of **Hydro One Remote Communities Inc.**

We have audited the balance sheets of **Hydro One Remote Communities Inc.** (the Company) as at December 31, 2009 and December 31, 2008, and the statements of operations and comprehensive income, retained earnings, accumulated other comprehensive income, and cash flows for the year then ended. 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 audit.

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 the Company as at December 31, 2009 and December 31, 2008, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
April 21, 2010

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in thousands)	**2009**	**2008**
Revenues *(Note 13)*	38,207	39,643
Costs		
Operation, maintenance and administration *(Note 13)*	11,886	12,095
Fuel used for electric generation	18,359	23,502
Depreciation and amortization *(Note 3)*	4,018	4,335
	34,263	39,932
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	3,944	(289)
Financing charges *(Notes 4 and 13)*	1,120	1,293
Income (loss) before provision for payments in lieu of corporate income taxes	2,824	(1,582)
Provision for (recovery of) payments in lieu of corporate income taxes *(Notes 5 and 13)*	2,824	(1,582)
Net income	-	-
Other comprehensive income	11	10
Comprehensive income	11	10

STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in thousands)	**2009**	**2008**
Accumulated other comprehensive income, January 1	(627)	(637)
Other comprehensive income	11	10
Accumulated other comprehensive income, December 31	(616)	(627)

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Assets		
Current assets:		
Inter-company demand facility *(Note 13)*	3,393	-
Accounts receivable (net of allowance for doubtful accounts - $878; 2008 - $798) *(Note 13)*	4,887	6,824
Fuel, materials and supplies	2,117	1,876
Future income tax assets *(Notes 2 and 5)*	395	-
Regulatory assets *(Note 7)*	1,665	2,265
	12,457	10,965
Fixed assets *(Note 6):*		
Fixed assets in service	48,966	45,008
Less: accumulated depreciation	24,296	22,623
	24,670	22,385
Construction in progress	2,418	3,053
Future use components and spares	1,213	1,153
	28,301	26,591
Other long-term assets:		
Regulatory assets *(Note 7)*	7,756	11,030
Future income tax assets *(Notes 2 and 5)*	4,255	-
Long-term accounts receivable (net of allowance for doubtful accounts - $633; 2008 - $940)	1,397	1,838
	13,408	12,868
Total assets	54,166	50,424

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS (continued)

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 13)*	-	5,512
Accounts payable and accrued charges	8,856	8,383
Regulatory liabilities *(Notes 2 and 7)*	395	-
Accrued interest	142	142
	9,393	14,037
Long-term debt *(Notes 8, 9 and 13)*	22,864	22,862
Other long-term liabilities:		
Employee future benefits other than pension *(Note 10)*	6,887	6,503
Environmental liabilities *(Note 11)*	7,756	7,649
Regulatory liabilities *(Notes 2 and 7)*	7,882	-
	22,525	14,152
Total liabilities	54,782	51,051
Contingency *(Note 15)*		
Shareholder's deficit		
Common shares (authorized: unlimited; issued 2) *(Note 12)*	-	-
Retained earnings	-	-
Accumulated other comprehensive income	(616)	(627)
Total shareholder's deficit	(616)	(627)
Total liabilities and shareholder's deficit	54,166	50,424

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)	**2009**	**2008**
Operating activities		
Net income	-	-
Environmental expenditures	(983)	(1,029)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	3,641	3,955
Gain on disposition of fixed assets	-	(6)
Remote rate protection revenue variance account	7,008	(4,845)
Amortization of debt costs	13	12
	9,679	(1,913)
Changes in non-cash balances related to operations *(Note 14)*	3,580	546
Net cash from (used in) operating activities	13,259	(1,367)
Investing activities		
Capital expenditures	(4,294)	(2,588)
Other	(60)	(83)
Net cash used in investing activities	(4,354)	(2,671)
Net change in inter-company demand facility	8,905	(4,038)
Inter-company demand facility, January 1	(5,512)	(1,474)
Inter-company demand facility, December 31	3,393	(5,512)

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS

1. DESCRIPTION OF THE 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 operates 19 small electrical, generation and distribution systems in remote northern communities that are not connected to Ontario's electricity grid. 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, 2009 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 recorded regulatory liabilities which represent amounts incurred in different periods than would be the case had the Company been unregulated. The Company's regulatory assets and liabilities recorded at December 31, 2009 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 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 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. On August 29, 2008, Hydro One Remote Communities filed a 2009 cost of service rate application proposing an increase of about $10 million over the previously approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all planned work program expenditures, a requested 4.4% rate increase effective May 1, 2009, and an annual amount of $27,549 thousand for rate protection for remote community customers.

On November 4, 2009, the Company filed an application for 2010 rates under the OEB's third generation Incentive Regulation Mechanism (IRM), seeking approval of an increase of approximately 2% to basic rates for the generation and distribution of electricity effective May 1, 2010, which would increase an average customer's total bill by 2%. The increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications. Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve breakeven results of operations, after consideration 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 May 26, 2009, the OEB issued a rate order approving Hydro One Remote Communities' request for $3,381 thousand in rate protection to clear the accumulated balance in the RRPR variance account. The OEB also approved Hydro One Remote Communities' proposal to file an annual continuity statement for the account for the purpose of clearing the annual balance in the RRPR variance account. The annual filing is designed to assist the OEB in calculating the annual amount of rate protection for customers of Hydro One Remote Communities.

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 *Taxation Act* (Ontario) (*Corporations Tax Act* (Ontario) prior to 2009) as modified by the *Electricity Act, 1998* and related regulations.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* and CICA Handbook Section 1100 - *Generally Accepted Accounting Principles.* These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the adoption of these amended sections requires the recognition of future income tax assets and liabilities, and correspondingly the recognition of regulatory liabilities and assets.

As a result of adopting these amended standards, on January 1, 2009, the Company recognized current future income tax assets of $1,128 thousand and long-term future income tax assets of $3,019 thousand. The Company also recognized corresponding current regulatory liabilities of $1,128 thousand and long-term regulatory liabilities of $3,019 thousand.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not to be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the Statement of Operations and Comprehensive Income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that they have become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-setting process.

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 consumables, 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.

Fixed assets in service consist of generation, distribution and administration and service assets. Fixed assets also include future use assets such as major components and spare parts and standby equipment.

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 in perpetuity, no asset retirement obligation exists. If, at some future date, a particular site is shown not to meet the perpetuity assumption, it will be reviewed to determine if an asset retirement obligation exists. If 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.

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 (2009 – 5.89%; 2008 – 5.32%).

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.

The Company periodically undergoes an external review of its fixed asset depreciation rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of the depreciation 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.

Discounts and Premiums

Discounts and premiums allocated by Hydro One based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue, are amortized over the term of the related debt using the effective interest method.

Financial Instruments

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 the Company's proportionate share of discontinued cash flow hedges. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt.

Financial Assets and Liabilities

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 are classified as loans and receivables or other financial liabilities and are measured at amortized cost. The Company has classified its financial instruments as follows:

Accounts Receivable	Loans and receivables
Long-term accounts receivable	Loans and receivables
Inter-company demand facility	Other liabilities
Accounts payable	Other liabilities
Long-term debt	Other liabilities

Derivatives and Hedge Accounting

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 or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. 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 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's documentation includes its risk management objective for establishing the hedging relationship, the identification of the hedged and hedging item, the nature of the specific risk exposure being hedged and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedged items that are being used are effective in offsetting changes in fair values or cash flows of hedged items.

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.

Financial Instrument Disclosures

Effective for the 2009 annual reporting period, the Company adopted amendments to the CICA Handbook Section 3862, *Financial Instruments – Disclosures.* The amended section improves financial instrument fair value measurement and liquidity risk management disclosures. The amendments require an entity to classify fair value measurements using a fair value hierarchy in levels ranging from 1 to 3 that reflect the significance of the inputs used in making these measurements. The amendments also provide clarification about the required liquidity risk disclosures. Upon application by the Company, the fair value hierarchy level used in the determination of the fair market value of the long-term debt has been disclosed in Note 9.

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 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

The Company records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands based on the 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 recorded 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).

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. As such, the Company will apply IFRS to its financial statements ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes.

The Company continues to assess the potential effects of the IFRS conversion on its financial position and results of operations. The International Accounting Standards Board (IASB) issued an exposure draft on rate regulated activities in July, 2009 and stakeholder comments on the draft varied substantially. In February, 2010, IASB staff presented its analysis of the various responses to the IASB and summarized options for next steps in the project. In response, the IASB asked staff to revisit the specific issue of whether or not rate-regulated assets and liabilities meet the definition of assets and liabilities under the IFRS framework. The outcome of this specific review, and of the rate-regulated activities project as a whole, cannot currently be predicted. As a result, the impact of the IASB's deliberations on the Company's reporting under IFRS is not estimable at this time.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in thousands)	**2009**	**2008**
Depreciation of fixed assets in service	2,658	2,597
Fixed asset removal costs	377	386
Gain on disposition	-	(6)
Amortization of regulatory assets	983	1,358
	4,018	4,335

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in thousands)	**2009**	**2008**
Interest on long-term debt payable	1,237	1,237
Interest on inter-company demand facility	19	84
Amortization of debt costs	13	12
Less: Interest capitalized on construction in progress	(156)	(134)
Other	7	94
	1,120	1,293

5. PROVISION FOR (RECOVERY OF) PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for (recovery of) 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. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in thousands)	**2009**	**2008**
Income before provision for PILs	2,824	(1,582)
Federal and Ontario statutory income tax rate	33.00%	33.50%
Provision for (recovery of) PILs at statutory rate	932	(530)
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
RRPR variance account	2,313	(1,634)
Environmental expenditures	(325)	(345)
Overhead capitalized for accounting purposes but deducted for tax purposes	(123)	(57)
Employee future benefits other than pension expense in excess of cash payments	65	139
Interest capitalized for accounting purposes but deducted for tax purposes	(52)	(45)
Other	(11)	91
Depreciation and amortization (less than) in excess of capital cost allowance	(3)	753
Net temporary differences	1,864	(1,098)
Net permanent differences	28	46
Total income tax provision for (recovery of) PILs	2,824	(1,582)
Current income tax provision for (recovery of) PILs	2,824	(1,582)
Future income tax provision for PILs	-	-
Total income tax provision for (recovery of) PILs	2,824	(1,582)
Effective income tax rate	100.00%	100.00%

The provision for payments in lieu of current income taxes of $2,824 thousand represents the amount that is payable to the OEFC with respect to current year earnings. The outstanding balance due to the OEFC of $870 thousand (2008 – due from the OEFC of $1,975 thousand) is included with accounts payable and accrued charges or accounts receivable on the Balance Sheet.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in thousands)	**2009**
Future income tax assets	
Employee future benefits other than pension expense in excess of cash payments	2,396
Depreciation and amortization in excess of capital cost allowance	1,540
Regulatory amounts received but not recognized for accounting purposes	962
Total future income tax assets	4,898
Less: current portion	395
	4,503

December 31 (Canadian dollars in thousands)	**2009**
Future income tax liabilities	
Debt costs unamortized for accounting purposes	248
Total future income tax liabilities	248
Less: current portion	-
	248

December 31 (Canadian dollars in thousands)	**2009**
Balance sheet classification of future income taxes	
Future income tax assets	4,898
Less: Future income tax liabilities	248
Total balance sheet classification of future income tax assets	4,650
Less: current portion	395
	4,255

6. FIXED ASSETS

December 31 (Canadian dollars in thousands)	Fixed Assets	Accumulated Depreciation	Construction In Progress	Total
2009				
Generation	36,786	21,025	1,761	17,522
Distribution	6,790	1,457	56	5,389
Administration and service	6,603	1,814	601	5,390
	50,179	24,296	2,418	28,301
2008				
Generation	33,482	19,870	2,536	16,148
Distribution	6,455	1,340	110	5,225
Administration and service	6,224	1,413	407	5,218
	46,161	22,623	3,053	26,591

Financing costs are capitalized on fixed assets under construction, using the OEB's approved allowance for funds used during construction, and were $156 thousand in 2009 (2008 - $134 thousand).

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities can arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Regulatory assets:		
Environmental	9,421	9,914
RRPR variance account	-	3,381
Total regulatory assets	9,421	13,295
Less: current portion	1,665	2,265
	7,756	11,030

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Regulatory liabilities:		
Regulatory future income tax liability	4,650	-
RRPR variance account	3,627	-
Total regulatory liabilities	8,277	-
Less: current portion	395	-
	7,882	-

Environmental

The Company records a liability for the estimated future expenditures required to remediate past environmental contamination *(Note 11)*. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. In 2009, the regulatory asset increased by $3 thousand to reflect related increases in the Company's land assessment and remediation (LAR) liability.

This environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been higher by $3 thousand (2008 - $390 thousand). In addition, amortization expense in 2009 would have been lower by $983 thousand (2008 - $1,029 thousand) and financing charges would have been higher by $487 thousand (2008 - $555 thousand).

RRPR Variance Account

The Company has recognized a regulatory account for remote rate protection amounts received that differ from amounts required to achieve a breakeven results of operations, after consideration of PILs. In the absence of rate-regulated accounting, revenue in 2009 would have been higher by $7,008 thousand (2008 – lower by $4,845 thousand).

Regulatory Future Income Tax Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory liabilities which correspond to future income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts set up for tax to be recovered through future rates. As a result the provision for PILs would have been lower by approximately $1,180 thousand (2008 – higher by $1,098 thousand) including the impact of a change in substantively enacted tax rates.

8. LONG-TERM DEBT

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Long-term debt	23,000	23,000
Net unamortized debt discount	(29)	(29)
Unamortized transaction costs	(107)	(109)
	22,864	22,862

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 transaction costs 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. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying values of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturity. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in thousands)	**2009**		**2008**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	23,000	22,306	23,000	19,626

[1] The carrying amount of long-term debt represents the par value of the note.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of losses that result from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk and foreign exchange risk is currently insignificant. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. In the year, the Company's provision for bad debts increased to $1,511 thousand (2008 - $1,738 thousand). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2009, approximately 39% of the Company's accounts receivable was aged more than 60 days. Sufficient allowances have been recorded to reflect the risk of potential credit losses.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through the inter-company demand facility currently available with Hydro One and funds generated from the Company's operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2009, accounts payable and accrued charges in the amount of $8,856 thousand (2008 - $8,383 thousand) are expected to be settled in cash at the carrying amounts within the next year. As at December 31, 2009, the Company has been allocated long-term debt in the amount of $23,000 thousand. The interest payments over the next twelve months related to that debt amount to $1,237 thousand.

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 with the Financial Services Commission of Ontario on September 20, 2007, effective for December 31, 2006, Hydro One contributed $112 million to its pension plan in respect of 2009 (2008 - $101 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 2009, 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 $155 million (2008 - $142 million).

For Hydro One, the actuarial present value at December 31, 2009 of the accrued pension benefits, based on a projection of the valuation at December 31, 2009, was estimated to be $4,740 million (2008 - $4,007 million). Pension plan assets available for these benefits were $4,336 million (2008 - $3,836 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2009, Hydro One Remote Communities charged $460 thousand (2008 - $659 thousand) of employee future benefits other than pension costs to results of operations and capitalized $190 thousand (2008 - $151 thousand) as part of the cost of fixed assets. Benefits paid by Hydro One Remote Communities were $266 thousand (2008 - $245 thousand). The liabilities, including the current portion, associated with employee future benefits other than pension for Hydro One Remote Communities at December 31, 2009 were $7,187 thousand (2008 - $6,803 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, 2009.

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Environmental liabilities, January 1	9,914	9,998
Interest accretion	487	555
Expenditures	(983)	(1,029)
Revaluation adjustment	3	390
Environmental liabilities, December 31	9,421	9,914
Less: current portion	(1,665)	(2,265)
	7,756	7,649

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2009 and in total thereafter are as follows: 2010 - $1,665 thousand; 2011 - $2,456 thousand; 2012 - $2,573 thousand; 2013 - $1,335 thousand; 2014 - $1,354 thousand; and 2015 - $613 thousand.

Consistent with its accounting policy for environmental costs, the Company records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands. The Company's liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. The revaluation adjustments in 2008 and 2009 were the result of net changes in estimated future expenditures, changes in timing of expected cash flows and carryforward of prior year spending variances.

There are uncertainties in estimating future environmental costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers of volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 4.87% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

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, OEFC, and 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, 2009 were $30,930 thousand (2008 - $21,097 thousand). Consistent with the breakeven business model, $23,922 thousand was recognized as revenue in

2009 (2008 - $25,942 thousand). The balance of the remote rate protection amounts received totaled $7,008 thousand. In 2008, revenue exceeded amounts received by $4,845 thousand. These differences were charged to or drawn from the RRPR variance 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 $2,206 thousand (2008 - $1,933 thousand) related to these services provided by Hydro One Networks Inc. The amounts due from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in thousands)	**2009**	**2008**
Accounts receivable	595	2,250

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 (2008 - $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 $19 thousand (2008 - $84 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)	**2009**	**2008**
Accounts receivable decrease (increase)	1,937	(302)
Fuel, materials and supplies (increase) decrease	(241)	748
Long-term accounts receivable decrease	441	397
Accounts payable and accrued charges increase (decrease)	1,073	(863)
Employee future benefits other than pension increase	384	562
Other	(14)	4
	3,580	546

Supplementary information:		
Interest paid	1,262	1,286

The Company does not make any payments in lieu of corporate income taxes as a result of using the cost recovery model applied to achieve breakeven results.

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. SUBSEQUENT EVENT

On April 14, 2010, the OEB issued a decision regarding 2010 rates under the OEB's third generation IRM which approves an increase to basic rates for the generation and distribution of electricity of approximately 0.4%, effective May 1, 2010. The increase reflects the standard inflationary, productivity and stretch factor adjustments that form the basis of the IRM process and formulaic adjustment to distribution rates.

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2010

HYDRO ONE REMOTE COMMUNITIES INC.
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheet as at December 31, 2010, the statements of operations and comprehensive income and accumulated other comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Hydro One Remote Communities Inc. as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
April 18, 2011

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in thousands)	**2010**	**2009**
Revenues *(Note 13)*	42,034	38,207
Costs		
Operation, maintenance and administration *(Note 13)*	14,598	11,886
Fuel used for electric generation	20,757	18,359
Depreciation and amortization *(Note 3)*	4,242	4,018
	39,597	34,263
Income before financing charges and provision for payments in lieu of corporate income taxes	2,437	3,944
Financing charges *(Notes 4 and 13)*	1,113	1,120
Income before provision for payments in lieu of corporate income taxes	1,324	2,824
Provision for payments in lieu of corporate income taxes *(Notes 5 and 13)*	1,324	2,824
Net income	-	-
Other comprehensive income	11	11
Comprehensive income	11	11

STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Year ended December 31 (Canadian dollars in thousands)	**2010**	**2009**
Accumulated other comprehensive income, January 1	(616)	(627)
Other comprehensive income	11	11
Accumulated other comprehensive income, December 31	(605)	(616)

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Assets		
Current assets:		
Inter-company demand facility *(Note 13)*	2,849	3,393
Accounts receivable (net of allowance for doubtful accounts - $825; 2009 - $878) *(Note 13)*	4,482	4,887
Regulatory assets *(Note 7)*	1,866	1,665
Fuel, materials and supplies	2,154	2,117
Income tax receivable	1,189	-
Future income tax assets *(Note 5)*	118	395
	12,658	12,457
Fixed assets *(Note 6):*		
Fixed assets in service	49,521	48,966
Less: accumulated depreciation	24,014	24,296
	25,507	24,670
Construction in progress	2,348	2,418
Future use components and spares	1,533	1,213
	29,388	28,301
Other long-term assets:		
Regulatory assets *(Note 7)*	6,426	7,756
Future income tax assets *(Note 5)*	5,598	5,119
Long-term accounts receivable (net of allowance for doubtful accounts - $50; 2009 - $633)	552	1,397
	12,576	14,272
Total assets	54,622	55,030

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS (continued)

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Liabilities		
Current liabilities:		
Accounts payable and accrued charges	8,827	9,451
Regulatory liabilities *(Note 7)*	118	395
Accrued interest	142	142
	9,087	9,988
Long-term debt *(Notes 8, 9 and 13)*	22,867	22,864
Other long-term liabilities:		
Regulatory liabilities *(Note 7)*	9,530	8,151
Employee future benefits other than pension *(Note 10)*	7,317	6,887
Environmental liabilities *(Note 11)*	6,426	7,756
	23,273	22,794
Total liabilities	55,227	55,646
Contingency *(Note 15)*		
Shareholder's deficit		
Common shares (authorized: unlimited; issued 2) *(Note 12)*	-	-
Retained earnings	-	-
Accumulated other comprehensive income	(605)	(616)
Total shareholder's deficit	(605)	(616)
Total liabilities and shareholder's deficit	54,622	55,030

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)	**2010**	**2009**
Operating activities		
Net income	-	-
Environmental expenditures	(1,268)	(983)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	4,083	3,641
Gain on disposition of fixed assets	(112)	-
Remote rate protection revenue variance account	305	7,008
Amortization of debt costs	14	13
	3,022	9,679
Changes in non-cash balances related to operations *(Note 14)*	240	3,580
Net cash from operating activities	3,262	13,259
Investing activities		
Capital expenditures	(3,598)	(4,294)
Other	(208)	(60)
Net cash used in investing activities	(3,806)	(4,354)
Net change in inter-company demand facility	(544)	8,905
Inter-company demand facility, January 1	3,393	(5,512)
Inter-company demand facility, December 31	2,849	3,393

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE 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 operates 19 small electrical, generation and distribution systems in remote northern communities that are not connected to Ontario's electricity grid. 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, 2010 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. 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 asset represents 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 have been 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 when the assessment is made. The Company's regulatory assets and liabilities are disclosed in Note 7.

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*. Remote rate protection amounts are collected by the Independent Electricity System Operator (IESO) through a charge to all Ontario customers and are paid to distributors, such as Hydro One Remote Communities, in accordance with the regulation under the *Ontario Energy Board Act, 1998*.

On November 4, 2009, the Company filed an application for 2010 rates under the OEB's third generation Incentive Regulation Mechanism (IRM). The OEB's Decision of April 14, 2010 approved an increase in rates for the distribution and generation of electricity of 0.38% effective May 1, 2010. This increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications.

On October 15, 2010, the Company filed an application for 2011 rates under the OEB's third generation IRM. The Company is seeking approval for an increase in rates for the distribution and generation of electricity of 0.38% effective May 1, 2011. The increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven results of operations, after consideration of payments in lieu of corporate income taxes (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 review and disposition by the OEB. On May 26, 2009, the OEB issued a rate order approving Hydro One Remote Communities' request for $3,381 thousand in rate protection to clear the accumulated balance in the RRPR variance account. This amount was recognized as revenue in 2009.

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 *Taxation Act, 2007* (Ontario) (*Corporations Tax Act* (Ontario) prior to 2009) as modified by the *Electricity Act, 1998* and related regulations.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from or payable to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not to be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the Statement of Operations and Comprehensive Income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that they have become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

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 consumables, 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.

Fixed assets in service consist of generation, distribution and administration and service assets. Fixed assets also include future use assets such as major components and spare parts.

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 in perpetuity, no asset retirement obligation exists. If, at some future date, a particular site is shown not to meet the perpetuity assumption, it will be reviewed to determine if an asset retirement obligation exists. If 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.

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 shared 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 (2010 – 4.34%; 2009 – 5.89%).

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.

The Company periodically undergoes an external review of its fixed asset depreciation rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of the depreciation 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%	3%

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 current 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 no asset retirement obligation has been recorded.

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.

Discounts and Premiums

Discounts and premiums allocated by Hydro One based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue are amortized over the term of the related debt using the effective interest method.

Financial Instruments

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 the Company's proportionate share of discontinued Hydro One cash flow hedges. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt.

Financial Assets and Liabilities

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 are classified as loans and receivables or other financial liabilities and are measured at amortized cost. The Company has classified its financial instruments as follows:

Accounts Receivable	Loans and receivables
Long-term accounts receivable	Loans and receivables
Inter-company demand facility	Other liabilities
Accounts payable	Other liabilities
Long-term debt	Other liabilities

Derivatives and Hedge Accounting

Derivative instruments are allocated by Hydro one, based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue. 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 or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. 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 Company does not engage in derivative trading or speculative activities.

Hydro One periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, Hydro One's documentation includes its risk management objective for establishing the hedging relationship, the identification of the hedged and hedging item, the nature of the specific risk exposure being hedged and the method for assessing effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedged items that are being used are effective in offsetting changes in fair values or cash flows of hedged items.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading are based on Hydro One Remote Communities' proportionate share of the relevant Hydro One transaction and 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.

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 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 benefits costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Company records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands based on the 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 recorded to reflect the future recovery of these expenditures 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).

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The Company continues to assess the impact of conversion to IFRS on its results of operations.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in thousands)	**2010**	**2009**
Depreciation of fixed assets in service	2,815	2,658
Fixed asset removal costs	271	377
Gain on disposition of fixed assets	(112)	-
Amortization of regulatory assets	1,268	983
	4,242	4,018

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in thousands)	**2010**	**2009**
Interest on long-term debt payable	1,237	1,237
Interest (income) expense on inter-company demand facility	(41)	19
Amortization of debt costs	14	13
Less: interest capitalized on construction in progress	(126)	(156)
Other	29	7
	1,113	1,120

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. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in thousands)	**2010**	**2009**
Income before provision for PILs	1,324	2,824
Federal and Ontario statutory income tax rate	31.00%	33.00%
Provision for PILs at statutory rate	410	932
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Depreciation and amortization in excess of (less than) capital cost allowance	1,181	(3)
Environmental expenditures	(393)	(325)
Overhead capitalized for accounting purposes but deducted for tax purposes	(108)	(123)
Employee future benefits other than pension expense in excess of cash payments	79	65
RRPR variance account	69	2,313
Interest capitalized for accounting purposes but deducted for tax purposes	(39)	(52)
Other	15	(11)
Net temporary differences	804	1,864
Net permanent differences	110	28
Total income tax provision for PILs	1,324	2,824
Current income tax provision for PILs	1,324	2,824
Future income tax provision for PILs	-	-
Total income tax provision for PILs	1,324	2,824
Effective income tax rate	100.00%	100.00%

The provision for payments in lieu of current income taxes of $1,324 thousand represents the amount that is payable to the OEFC with respect to current year earnings. There is a balance due from the OEFC of $1,189 thousand (2009 - $2,824 thousand due to the OEFC) included within accounts receivable or accounts payable and accrued charges on the Balance Sheet.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Future income tax assets		
Employee future benefits other than pension expense in excess of cash payments	2,556	2,394
Depreciation and amortization in excess of capital cost allowance	2,085	1,732
Regulatory amounts received but not recognized for accounting purposes	1,310	1,707
Total future income tax assets	5,951	5,833
Less: current portion	118	395
	5,833	5,438

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Future income tax liabilities		
Debt costs unamortized for accounting purposes	235	319
Total future income tax liabilities	235	319
Less: current portion	-	-
	235	319

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Balance sheet classification of future income taxes		
Future income tax assets	5,951	5,833
Less: future income tax liabilities	235	319
Total balance sheet classification of future income tax assets	5,716	5,514
Less: current portion	118	395
	5,598	5,119

6. FIXED ASSETS

December 31 (Canadian dollars in thousands)	Fixed Assets	Accumulated Depreciation	Construction In Progress	Total
2010				
Generation	36,722	20,705	2,063	18,080
Distribution	7,237	1,562	228	5,903
Administration and service	7,095	1,747	57	5,405
	51,054	24,014	2,348	29,388
2009				
Generation	36,786	21,025	1,761	17,522
Distribution	6,790	1,457	56	5,389
Administration and service	6,603	1,814	601	5,390
	50,179	24,296	2,418	28,301

Financing costs are capitalized on fixed assets under construction, using the OEB's approved allowance for funds used during construction, and were $126 thousand in 2010 (2009 - $156 thousand).

7. REGULATORY ASSET AND LIABILITIES

Regulatory assets and liabilities can arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory asset and liabilities:

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Regulatory asset:		
Environmental	8,292	9,421
Less: current portion	1,866	1,665
	6,426	7,756

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Regulatory liabilities:		
Regulatory future income tax liability	5,716	4,919
RRPR variance account	3,932	3,627
Total regulatory liabilities	9,648	8,546
Less: current portion	118	395
	9,530	8,151

Environmental

The Company records a liability for the estimated future expenditures required to remediate past environmental contamination *(Note 11)*. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2010, the carrying value of the regulatory asset was reduced by $356 thousand to reflect a revaluation adjustment in the Company's environmental liabilities.

This environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $356 thousand (2009 – higher by $3 thousand). In addition, amortization expense in 2010 would have been lower by $1,268 thousand (2009 - $983 thousand) and financing charges would have been higher by $495 thousand (2009 - $487 thousand).

Regulatory Future Income Tax Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs would have been lower by approximately $148 thousand (2009 – $1,180 thousand) including the impact of a change in substantively enacted tax rates.

RRPR Variance Account

The Company has recognized a regulatory account representing remote rate protection amounts received that differ from amounts required to achieve a breakeven results of operations, after consideration of PILs. In the absence of rate-regulated accounting, revenue in 2010 would have been higher by $305 thousand (2009 - $7,008 thousand).

8. LONG-TERM DEBT

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Long-term debt	23,000	23,000
Net unamortized debt discount	(28)	(29)
Unamortized transaction costs	(105)	(107)
	22,867	22,864

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 transaction costs 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. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying values of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturity. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in thousands)	**2010**		**2009**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	23,000	24,592	23,000	22,306

[1] The carrying amount of long-term debt represents the par value of the note.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of losses that result from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk and foreign exchange risk is currently insignificant. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. In the year, the Company's provision for bad debts decreased to $875 thousand (2009 - $1,511 thousand). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2010, approximately 50% of the Company's accounts receivable was aged more than 60 days. Sufficient allowances have been recorded to reflect the risk of potential credit losses.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through the inter-company demand facility currently available with Hydro One and funds generated from the Company's operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2010, accounts payable and accrued charges in the amount of $8,773 thousand (2009 - $9,451 thousand) are expected to be settled in cash at the carrying amounts within the next year. As at December 31, 2010, the Company's debt payable to Hydro One is $23,000 thousand. The interest payments over the next twelve months related to that debt amount to $1,237 thousand.

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 Inc. 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 with the Financial Services Commission of Ontario (FSCO) in September 2010, effective for December 31, 2009, Hydro One contributed $193 million to its pension plan in respect of 2010 (2009 - $112 million), $145 million of which is required to satisfy minimum funding requirements. Hydro One made an additional payment of $48 million in December 2010. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2012 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2010, consisting of cash contributed by Hydro One to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $233 million (2009 - $155 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2010, Hydro One Remote Communities charged $512 thousand (2009 - $460 thousand) of employee future benefits other than pension costs to results of operations and capitalized $176 thousand (2009 - $190 thousand) as part of the cost of fixed assets. Benefits paid by Hydro One Remote Communities were $258 thousand (2009 - $266 thousand). The liabilities, including the current portion, associated with employee future benefits other than pension for Hydro One Remote Communities at December 31, 2010 were $7,617 thousand (2009 - $7,187 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, 2010.

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Environmental liabilities, January 1	9,421	9,914
Interest accretion	495	487
Expenditures	(1,268)	(983)
Revaluation adjustment	(356)	3
Environmental liabilities, December 31	8,292	9,421
Less: current portion	(1,866)	(1,665)
	6,426	7,756

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2010 and in total thereafter are as follows: 2011 - $1,866 thousand; 2012 - $2,268 thousand; 2013 - $2,401 thousand; 2014 - $1,520 thousand; 2015 - $622 thousand; and thereafter - $nil.

Consistent with its accounting policy for environmental costs, the Company records a liability for the estimated future expenditures associated with the Company's land assessment and remediation (LAR) program. The Company's LAR liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. The revaluation adjustments in 2009 and 2010 were the result of net changes in the estimated timing and amount of future expenditures.

There are uncertainties in estimating future environmental expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 4.87% to 6.25%, depending on the appropriate rate for the period when the obligations were first recorded.

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, OEFC, and 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, 2010 were $27,549 thousand (2009 - $30,930 thousand). Consistent with the breakeven business model, $27,244 thousand was recognized as revenue in 2010 (2009 - $23,922 thousand). The balance of the remote rate protection amounts received totaled $305 thousand (2009 - $7,008). These amounts were charged to the RRPR variance account.

The provision for PILs was paid or payable to the OEFC.

The amounts due from/to related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in thousands)	**2010**	**2009**
Accounts receivable	1,189	-
Accounts payable and accrued charges	-	(1,465)

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 $2,533 thousand (2009 - $2,298 thousand) related to these services provided by Hydro One Networks Inc. In addition, revenue includes $267 thousand (2009 - $93 thousand) for services provided to Hydro One and its subsidiaries.

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 (2009 - $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 revenue on this facility in the amount of $41 thousand (2009 - $19 thousand expense).

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)	**2010**	**2009**
Accounts receivable decrease	405	1,937
Income taxes receivable increase	(1,189)	-
Fuel, materials and supplies increase	(37)	(241)
Long-term accounts receivable decrease	845	441
Accounts payable and accrued charges (decrease) increase	(230)	1,073
Employee future benefits other than pension increase	430	384
Other	16	(14)
	240	3,580
Supplementary information:		
Net interest paid on long-term debt and inter-company demand facility	1,196	1,256

The Company does not make any payments in lieu of corporate income taxes as a result of using the cost recovery model applied to achieve after tax breakeven results of operations.

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. SUBSEQUENT EVENTS

On March 28, 2011, the OEB issued its decision regarding the Company's 2011 cost-of-service rate application. The OEB approved the submission on the basis of the OEB's third-generation incentive regulation mechanism policies. The revised rates were approved with an implementation date of May 1, 2011 and reflect an increase of approximately 0.38% on an average residential customer's overall monthly bill.

17. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2010 financial statements.

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2011

HYDRO ONE REMOTE COMMUNITIES INC.
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Remote Communities Inc.

We have audited the accompanying financial statements of Hydro One Remote Communities Inc., which comprise the balance sheets as at December 31, 2011, the statements of operations and comprehensive income and accumulated other comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Hydro One Remote Communities Inc. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
April 2, 2012

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Years ended December 31 (Canadian dollars in thousands)	**2011**	**2010**
Revenues *(Note 13)*	43,472	42,034
Costs		
Operation, maintenance and administration *(Note 13)*	15,610	14,598
Fuel used for electric generation	22,161	20,757
Depreciation and amortization *(Note 3)*	4,694	4,242
	42,465	39,597
Income before financing charges and provision for payments in lieu of corporate income taxes	1,007	2,437
Financing charges *(Notes 4 and 13)*	1,134	1,113
Income before provision for payments in lieu of corporate income taxes	(127)	1,324
(Recovery of) provision for payments in lieu of corporate income taxes *(Notes 5 and 13)*	(127)	1,324
Net income	-	-
Other comprehensive income	11	11
Comprehensive income	11	11

STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Years ended December 31 (Canadian dollars in thousands)	**2011**	**2010**
Accumulated other comprehensive income, January 1	(605)	(616)
Other comprehensive income	11	11
Accumulated other comprehensive income, December 31	(594)	(605)

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Assets		
Current assets:		
Inter-company demand facility *(Note 13)*	-	2,849
Accounts receivable (net of allowance for doubtful accounts - $430; 2010 - $825) *(Note 13)*	3,935	4,482
Regulatory assets *(Note 7)*	3,402	1,866
Fuel, materials and supplies	2,817	2,154
Income tax receivable	163	1,189
Future income tax assets *(Note 5)*	107	118
	10,424	12,658
Fixed assets *(Note 6):*		
Fixed assets in service	52,622	49,521
Less: accumulated depreciation	24,128	24,014
	28,494	25,507
Construction in progress	3,679	2,348
Future use components and spares	1,550	1,533
	33,723	29,388
Other long-term assets:		
Regulatory assets *(Note 7)*	11,177	6,426
Future income tax assets *(Note 5)*	5,667	5,598
Long-term accounts receivable (net of allowance for doubtful accounts - $228; 2010 - $50)	369	552
	17,213	12,576
Total assets	61,360	54,622

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS (continued)

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 13)*	2,212	-
Accounts payable and accrued charges	8,793	8,827
Regulatory liabilities *(Note 7)*	107	118
Accrued interest	142	142
	11,254	9,087
Long-term debt *(Notes 8, 9 and 13)*	22,870	22,867
Other long-term liabilities:		
Regulatory liabilities *(Note 7)*	8,765	9,530
Employee future benefits other than pension *(Note 10)*	7,888	7,317
Environmental liabilities *(Note 11)*	11,177	6,426
	27,830	23,273
Total liabilities	61,954	55,227
Contingency *(Note 15)*		
Shareholder's deficit		
Common shares (authorized: unlimited; issued 2) *(Note 12)*	-	-
Retained earnings	-	-
Accumulated other comprehensive income	(594)	(605)
Total shareholder's deficit	(594)	(605)
Total liabilities and shareholder's deficit	61,360	54,622

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)	**2011**	**2010**
Operating activities		
Net income	-	-
Environmental expenditures	(1,017)	(1,268)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	3,926	4,083
Gain on disposition of fixed assets	-	(112)
Remote rate protection revenue variance account	(834)	305
Loss on interest rebate swap agreements	12	12
Amortization of debt costs	2	2
	2,089	3,022
Changes in non-cash balances related to operations *(Note 14)*	96	240
Net cash from operating activities	2,185	3,262
Investing activities		
Capital expenditures	(7,229)	(3,598)
Future use assets	(17)	(208)
Net cash used in investing activities	(7,246)	(3,806)
Net change in inter-company demand facility	(5,061)	(544)
Inter-company demand facility, January 1	2,849	3,393
Inter-company demand facility, December 31	(2,212)	2,849

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE 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 operates 19 small electrical, generation and distribution systems in remote northern communities that are not connected to Ontario's electricity grid. 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, 2011 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. 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 asset represents 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 that represent amounts for expenses incurred in different periods than would have been the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory asset and continues to believe that it is probable that the OEB will factor its regulatory asset 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 when the assessment is made. The Company's regulatory asset and liabilities are disclosed in Note 7.

Revenue Recognition and the Remote Rate Protection Revenue Variance Account

Revenues attributable to the generation and 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*. Remote rate protection amounts are collected by the Independent Electricity System Operator (IESO) through a charge to all Ontario customers and are paid to distributors, such as Hydro One Remote Communities, in accordance with a regulation under the *Ontario Energy Board Act, 1998*.

On November 4, 2009, the Company filed an application for 2010 rates under the OEB's third generation Incentive Regulation Mechanism (IRM). The OEB's Decision of April 14, 2010 approved an increase in rates for the distribution and generation of electricity of 0.38% effective May 1, 2010. This increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications.

Hydro One Remote Communities filed an application for 2011 rates under the OEB's third generation Incentive Regulation Mechanism (IRM) on October 15, 2010. The OEB's decision of March 28, 2011 approved an increase in basic rates for the generation and distribution of electricity of 0.38% effective May 1, 2011. The increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications.

On November 25, 2011, an application for 2012 distribution rates was filed under the OEB's third generation IRM seeking approval for an increase to basic rates for the distribution and generation of electricity of 0.38% effective May 1, 2012.

Consistent with the OEB's Decision allowing the use of US GAAP as the rate setting and regulatory reporting framework for Hydro One Networks Inc.'s Transmission Business, on December 16, 2011 the Company submitted an application to adopt US GAAP as its basis for its own rate setting and regulatory reporting. A decision is anticipated in the second quarter of 2012.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven results of operations, after consideration of payments in lieu of corporate income taxes (PILs). Any excess or deficiency in remote rate protection amounts 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 review and disposition by the OEB.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to pay its PILs to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (*Corporations Tax Act* (Ontario) prior to 2009) as modified by the *Electricity Act, 1998* and related regulations.

Current Income Taxes

The provision for current taxes and the tax assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not to be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the Statement of Operations and Comprehensive Income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that they have become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

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 consumables, 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.

Fixed assets in service consist of generation, distribution and administration and service assets. Fixed assets also include future use assets such as major components and spare parts.

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 in perpetuity, no asset retirement obligation exists. If, at some future date, a particular site is shown not to meet the perpetuity assumption, it will be reviewed to determine if an asset retirement obligation exists. If 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.

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 shared 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 (2011 – 4.20%; 2010 – 4.34%).

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.

The Company periodically undergoes an external review of its fixed asset depreciation rates, as required by the OEB. Any changes arising from the periodic review of asset service lives are implemented on a remaining service life basis consistent with their inclusion in rates. The last review resulted in changes to rates effective January 1, 2007. A summary of the depreciation rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Generation	1% - 13%	6%
Distribution	1% - 10%	3%
Administration and service	3% - 20%	3%

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 current 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 no asset retirement obligation has been recorded.

Discounts and Premiums

Discounts and premiums allocated by Hydro One based on Hydro One Remote Communities' proportionate share of the relevant Hydro One debt issue are amortized over the term of the related debt using the effective interest method.

Financial Instruments

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of hedging losses on the Company's proportionate share of discontinued Hydro One cash flow hedges. The Company amortizes its hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the allocated hedged debt.

Financial Assets and Liabilities

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 are classified as loans and receivables or other financial liabilities and are measured at amortized cost. The Company has classified its financial instruments as follows:

Accounts Receivable	Loans and receivables
Long-term accounts receivable	Loans and receivables
Inter-company demand facility	Other liabilities
Accounts payable	Other liabilities
Long-term debt	Other liabilities

Derivatives and Hedge Accounting

The Company does not engage in derivative trading or speculative activities and has no derivative instruments outstanding as of December 31, 2011.

However Hydro One Inc., the holding company, periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, Hydro One's documentation includes its risk management objective for establishing the hedging relationship, the identification of the hedged and hedging item, the nature of the specific risk exposure being hedged and the method for assessing effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedged items that are being used are effective in offsetting changes in fair values or cash flows of hedged items.

Comprehensive Income

Comprehensive income is comprised of Remotes' net income and OCI. OCI includes the monthly amortization of net unamortized hedging gains or losses on the Company's proportionate share of the realized gains or losses on Hydro One's advance rate setting hedges.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading are based on Hydro One Remote Communities' proportionate share of the relevant Hydro One transaction and 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.

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 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 benefits costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Company records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands based on the 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 recorded to reflect the future recovery of these expenditures 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).

Emerging Accounting Changes

Accounting Framework

The Company previously anticipated it would apply International Financial Reporting Standards (IFRS) to the Financial Statements of its regulated businesses for fiscal periods beginning on or after January 1, 2012. In the absence of a definitive plan for a new project to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, Hydro One began evaluating the option of adopting US GAAP in lieu of IFRS in the first quarter of this year. On July 7, 2011, Hydro One filed an application with the Ontario Securities Commission (OSC) for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 Acceptable Accounting Policies and Auditing Standards that would otherwise require it to file Financial Statements based on IFRS starting with reporting periods commencing after January 1, 2012. Hydro One's application requested approval to instead adopt US GAAP, without becoming a Securities and Exchange Commission registrant, for its 2012, 2013 and 2014 fiscal years. On July 21, 2011, the OSC approved Hydro One's application and granted it the requested exemptive relief. Hydro One's Board of Directors has approved a resolution authorizing it to report under US GAAP.

As a result, the Company, as a subsidiary of Hydro One, will prepare its December 31, 2012 Financial Statements based on US GAAP with two years of comparative restatement. The Company's opening US GAAP Balance Sheet will be based on a retrospective application of US GAAP. The Company anticipates that its current application of Canadian GAAP for rate-regulated activities will generally be consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on the Company's Financial Statements will be assessed as part of the Company's US GAAP conversion project.

On December 16, 2011, the Company submitted an application to the OEB asking for approval to adopt US GAAP as its approved basis for rate-setting and regulatory accounting and reporting in preference to modified IFRS.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in thousands)	**2011**	**2010**
Depreciation of fixed assets in service	2,909	2,815
Fixed asset removal costs	768	271
Gain on disposition of fixed assets	-	(112)
Amortization of regulatory assets	1,017	1,268
	4,694	4,242

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in thousands)	**2011**	**2010**
Interest on long-term debt payable	1,237	1,237
Interest expense (income) on inter-company demand facility	19	(41)
Amortization of debt costs	2	2
Loss on interest rebate swap agreements	12	12
Other	30	29
Less: interest capitalized on construction in progress	166	126
	1,134	1,113

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. The reconciliation between the statutory and effective tax rates is provided as follows:

(Canadian dollars in thousands)	**2011**	**2010**
(Loss) Income before provision for PILs	(127)	1,324
Federal and Ontario statutory income tax rate	28.25%	31.00%
(Recovery of) provision for PILs at statutory rate	(36)	410
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Depreciation and amortization in excess of capital cost allowance	585	1,181
Environmental expenditures	(287)	(393)
Overhead capitalized for accounting purposes but deducted for tax purposes	(138)	(108)
Employee future benefits other than pension expense in excess of cash payments	86	79
RRPR variance account	(236)	69
Interest capitalized for accounting purposes but deducted for tax purposes	(47)	(39)
Pension contributions in excess of pension expense	(88)	-
Other	4	15
Net temporary differences	(121)	804
Net permanent differences	30	110
Total income tax (recovery of) provision for PILs	(127)	1,324
Current income tax provision for PILs	(127)	1,324
Future income tax provision for PILs	-	-
Total income tax (recovery of) provision for PILs	(127)	1,324
Effective income tax rate	100%	100%

The recovery of payments in lieu of current income taxes of $127 thousand represents the amount that is recoverable from the OEFC with respect to current year earnings. There is a balance receivable from the OEFC of $163 thousand (2010 - $1,189 thousand).

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Future income tax assets		
Employee future benefits other than pension expense in excess of cash payments	2,736	2,556
Depreciation and amortization in excess of capital cost allowance	2,237	2,085
Regulatory amounts received but not recognized for accounting purposes	1,032	1,310
Total future income tax assets	6,005	5,951
Less: current portion	107	118
	5,898	5,833

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Future income tax liabilities		
Debt costs unamortized for accounting purposes	231	235
Total future income tax liabilities	231	235
Less: current portion	-	-
	231	235

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Balance sheet classification of future income taxes		
Future income tax assets	6,005	5,951
Future income tax liabilities	(231)	(235)
Total balance sheet classification of future income tax assets	5,774	5,716
Less: current portion	107	118
	5,667	5,598

6. FIXED ASSETS

December 31 (Canadian dollars in thousands)	Costs	Accumulated Depreciation	Construction In Progress	Total
2011				
Generation	38,259	20,895	2,966	20,330
Distribution	7,485	1,612	202	6,075
Administration and service	8,428	1,621	511	7,318
	54,172	24,128	3,679	33,723
2010				
Generation	36,722	20,705	2,063	18,080
Distribution	7,237	1,562	228	5,903
Administration and service	7,095	1,747	57	5,405
	51,054	24,014	2,348	29,388

Financing costs are capitalized on fixed assets under construction, using the OEB's approved allowance for funds used during construction, and were $166 thousand in 2011 (2010 - $126 thousand).

7. REGULATORY ASSET AND LIABILITIES

Regulatory assets and liabilities can arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory asset and liabilities:

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Regulatory asset:		
Environmental	14,579	8,292
Less: current portion	3,402	1,866
	11,177	6,426

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Regulatory liabilities:		
Future income tax regulatory liability	5,774	5,716
RRPR variance account	3,098	3,932
Total regulatory liabilities	8,872	9,648
Less: current portion	107	118
	8,765	9,530

Environmental

The Company records a liability *(Note 11)* 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 recorded an equivalent amount as a regulatory asset. In 2011, the carrying value of the regulatory asset was increased by $7,043 thousand to reflect a revaluation adjustment in the Company's environmental liabilities.

This environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $7,043 thousand (2010 - higher by $356 thousand). In addition, amortization expense in 2011 would have been lower by $1,017 thousand (2010 - $1,268 thousand) and financing charges would have been higher by $261 thousand (2010 - $495 thousand).

Future Income Tax Regulatory Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the provision for PILs would have been lower by approximately $154 thousand (2010 – $148 thousand) including the impact of a change in substantively enacted tax rates.

RRPR Variance Account

The Company has recognized a regulatory account representing remote rate protection amounts received that differ from amounts required to achieve a breakeven results of operations, after consideration of PILs. In the absence of rate-regulated accounting, revenue in 2011 would have been lower by $835 thousand (2010 – higher by $305 thousand).

8. LONG-TERM DEBT

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Long-term debt	23,000	23,000
Net unamortized debt discount	(28)	(28)
Unamortized transaction costs	(102)	(105)
	22,870	22,867

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 unamortized debt discount and transaction costs represent 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. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying values of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturity. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in thousands)	**2011**		**2010**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	23,000	27,844	23,000	24,592

[1] The carrying value of long-term debt represents the par value of the note.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of losses that result from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk and foreign exchange risk is currently insignificant. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. In the year, the Company's provision for bad debts decreased to $658 thousand (2010 - $875 thousand). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2011, approximately 32% of the Company's accounts receivable was aged more than 60 days. Sufficient allowances have been recorded to reflect the risk of potential credit losses.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through the inter-company demand facility currently available with Hydro One and funds generated from the Company's operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2011, accounts payable and accrued charges in the amount of $8,793 thousand (2010 - $8,827 thousand) are expected to be settled in cash at the carrying amounts within the next year. As at December 31, 2011, the Company's debt payable to Hydro One is $23,000 thousand. The interest payments over the next twelve months related to that debt amount to $1,237 thousand.

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 Inc. 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 with the Financial Services Commission of Ontario (FSCO) in September 2010, effective for December 31, 2009, Hydro One contributed $152 million to its pension plan in respect of 2011 (2010 - $193 million), $148 million of which is required to satisfy minimum funding requirements (2010 - $145 million). Hydro One made an additional payment of $48 million in December 2010 and an additional payment in 2011 of $4 million related to a partial plan wind-up. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Future contributions will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2011, consisting of cash contributed by Hydro One to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $195 million (2010 - $233 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2011, Hydro One Remote Communities charged $551 thousand (2010 - $512 thousand) of employee future benefits other than pension costs to results of operations and capitalized $271 thousand (2010 - $176 thousand) as part of the cost of fixed assets. Benefits paid by Hydro One Remote Communities were $248 thousand (2010 - $258 thousand). The liabilities, including the current portion, associated with employee future benefits other than pension for Hydro One Remote Communities at December 31, 2011 were $8,188 thousand (2010 - $7,617 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, 2011.

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Environmental liabilities, January 1	8,292	9,421
Interest accretion	261	495
Expenditures	(1,017)	(1,268)
Revaluation adjustment	7,043	(356)
Environmental liabilities, December 31	14,579	8,292
Less: current portion	3,402	1,866
	11,177	6,426

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2011 and in total thereafter are as follows: 2012 - $3,402 thousand; 2013 - $2,603 thousand; 2014 - $1,401 thousand; 2015 - $1,468 thousand; 2016 - $1,027 thousand; and thereafter - $5,519.

Consistent with its accounting policy for environmental costs, the Company records a liability for the estimated future expenditures associated with the Company's land assessment and remediation (LAR) program. The Company's LAR liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. The revaluation adjustments in 2010 and 2011 were the result of net changes in the estimated timing and amount of future expenditures.

There are uncertainties in estimating future environmental expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 6.25%, depending on the appropriate rate for the period when the obligations were first recorded.

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, OEFC, and 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, 2011 were $27,549 thousand (2010 - $27,549 thousand). Consistent with the breakeven business model, $28,384 thousand was recognized as revenue in 2011 (2010 - $27,244 thousand). The balance of the remote rate protection amounts received totaled $835 thousand and was drawn from the RRPR variance account. In 2010, revenue exceeded amounts received by $305 thousand and was credited to the RRPR variance account.

The amounts due from/to related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in thousands)	**2011**	**2010**
Accounts receivable	163	1,189
Accounts payable and accrued charges	-	-

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 $1,918 thousand (2010 - $2,533 thousand) related to these services provided by Hydro One Networks Inc. In addition, revenue includes $173 thousand (2010 - $267 thousand) for services provided to Hydro One and its subsidiaries.

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 (2010 - $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 $19 thousand (2010 - $41 thousand interest revenue).

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)	**2011**	**2010**
Accounts receivable decrease	547	405
Fuel, materials and supplies increase	(663)	(37)
Income taxes receivable decrease (increase)	1,026	(1,189)
Long-term accounts receivable decrease	183	845
Accounts payable and accrued charges decrease	(1,570)	(230)
Employee future benefits other than pension increase	571	430
Other	2	16
	96	240

Supplementary information:		
Net interest paid on long-term debt and inter-company demand facility	1,256	1,196

As a result of using the cost recovery model applied to achieve after tax breakeven results of operations, any PILs are fully recovered.

15. CONTINGENCY

The transfer orders by which Hydro One Remote Communities acquired Ontario Hydro's remote communities business on April 1, 1999 did not transfer 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 legal title to these assets and the Company manages them until the necessary authorizations have been obtained to complete the title transfer. OEFC will continue to hold these assets until the Company is able to negotiate agreements with the Indian bands and occupants.

16. SUBSEQUENT EVENTS

On March 22, 2012, the OEB issued its decision regarding the Company's application for 2012 distribution rates. The OEB approved the submission on the basis of the OEB's third-generation incentive regulation mechanism policies. The revised rates were approved with an implementation date of May 1, 2012 and reflect an increase of 1.08% on a customer's overall monthly bill.

17. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2011 financial statements.

Hydro One Remote Communities Inc.
Reconciliation of Regulatory Financial Results with Audited Financial Statements
For year ending December 31, 2011

	Audited Financial Statements Exhibit A-10-1, Att 3	Adjustments	Regulatory Financial Results
Revenue			
Remotes Revenue	15,088		15,088
RRRP	28,384		28,384
	43,472	-	43,472
Costs			
OM&A (Note 1)	15,610	31	15,641
Cost of fuel	22,161		22,162
Depreciation	4,694		4,694
Taxes other than income tax (Note 1)		(31)	(31)
	42,465	-	42,465
Income before financing charges and provision for payments in lieu of corporate income taxes	1,007	-	1,007
Financing Charges	1,134		1,134
Income before provision for payments in lieu of corporate income taxes	(127)	-	(127)
Provision for Payments in lieu of corporate income taxes (Note 2)	(127)	(37)	(164)
Net Income	-	(37)	(37)

Note 1: Capital taxes are included in Remotes audited OM&A total, whereas in the rate evidence are shown as a separate line item.

Note 2: Difference relates to actual recovery per 2011 tax return

HYDRO ONE REMOTE COMMUNITIES INC.
2011 Financial Statements reconciled to USofA Trial balance

BALANCE SHEET (December 31, 2011)

	Financial Statement item	**USofA Account/s**	**$thousands**
	ASSETS		
	Current assets		
1	Accounts receivable	1100, 1105, 1110, 1130	3,935
2	Fuel, materials and supplies	1305, 1330	2,817
3	Regulatory assets	1525, 1590	3,402
4	Income tax receivable	2296	163
5	Future income tax assets	1190	107
6	Current Assets		10,424
	Fixed assets in service		
7	Generation Plant	1615, 1620, 1650, 1665, 1670, 1675, 1680, 1685	37,907
8	Distribution Plant	1805, 1806, 1830, 1835, 1845, 1850, 1860	6,307
9	General Plant	1908, 1910, 1915, 1920, 1935, 1940, 1945, 1955, 1960	8,408
10	Fixed Assets in Service		52,622
11	Less: accumulated depreciation	2105	24,128
12			
			28,494
	Construction in progress	2055	3,679
13	Future use assets	2040	1,550
14	Long-term Assets		33,723
	Other long-term assets		
15	Regulatory assets	1460, 1525	11,177
16	Future income tax receivable	1460	5,667
17	Long-term accounts receivable & other assets	1180, 1460	369
18	Other Long-term Assets		17,213
19	**TOTAL ASSETS**		**61,360**
	LIABILITIES		
	Current liabilities		
20	Inter-company demand facility	2240	2,212
21	Accounts payable and accrued charges	2205, 2210, 2220, 2250, 2290, 2292, 2294, 2296	8,793
22	Regulatory Liabilities	2296	107
23	Accrued interest	2268	142
24	Current Liabilities		11,254
25	Long-term debt	1425, 2530	**22,870**
	Other long-term liabilities		
26	Regulatory liabilities-retail settlement variance accounts	2350, 2405	8,765
27	Environmental liabilities	2320	11,177
28	Employee Future Benefits Other Than Pension	2306	7,888
29	Other Long Term Liabilities		27,830
30	**TOTAL LIABILITIES**		**61,954**
31	Contingencies and commitments		**0**
32	Accumulated other comprehensive income	3040, 4375	**(594)**
33	**TOTAL LIABILITIES and EXCESS OF ASSETS OVER LIABILITIES**		**61,360**

HYDRO ONE REMOTE COMMUNITIES INC.

2011 FINANCIAL STATEMENTS RECONCILED TO USofA TRIAL BALANCE
Statement of Operations (Year ended December 31, 2011)

	Financial Statement item	USofA Account/s		$ thousands
	REVENUES			
34	Energy sales	4006, 4010, 4025	$	14,336
35	Rural rate protection	4105		28,384
36	Late payment charge	4225		297
37	Other revenue	4235, 4325		455
38	TOTAL REVENUE			43,472
	COSTS			
39	Fuel used for electric generation	4510		22,162
	Operation, maintenance & administration			
40	Generation	4550, 4555, 4610, 4635		10,996
41	Distribution	5085, 5120, 5125, 5130, 5135, 5175		1,344
42	Customer care	5310, 5315, 5320, 5335		1,734
43	Community relations	5410, 5415, 5420, 5425		444
44	Administrative and other expenses	4330, 5615, 5625, 5655, 6105, 6205		1,091
45	Depreciation and amortization	5705, 5715, 5740,		4,694
46	TOTAL COSTS			42,465
47	**Income before financing charges & provision for payments in lieu of corporate income taxes**			1,007
48	Financing charges	6005, 6010, 6035, 6040		1,134
49	**Income before provision for payments in lieu of corporate income taxes**			(127)
50	Provision for payments in lieu of corporate income taxes	6110		(127)
51	**Net income**		**$**	**(0)**
52	Other comprehensive income	4375		11
53	Comprehensive income		$	11

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.

Remotes has requested certain exemptions from the DSC as they relate to residential customer collections and account servicing. The Board is considering this matter under EB-2011-0118. A decision had not been released at the time of this submission. Remotes estimates the cost of adhering to the rules in the DSC at approximately $2M. The costs associated with implementing these rules are not included in Remotes' revenue requirement.

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, Schedule 2, page 9.

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 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.

3.3.3 Land Assessment and Remediation ("LAR")

LAR is discussed in more detail in Exhibit C1, Tab 4, Schedule 1, Appendix A

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.
- Due diligence safety inspections conducted by the Electrical Safety Authority ("ESA") to ensure safety standards are met.

Electrical safety is a high priority for Remotes, as indicated in the strategic goals in Exhibit A, Tab 4, Schedule 1. To address this priority Remotes has implemented comprehensive training programs to ensure all Electrical Safety Regulations are adhered to across the business. The ESA also undertakes regular compliance reviews to ensure that Remotes work complies with distribution standards and the overall objectives of Regulation 22/04.

5.0 TRANSMISSION IN THE NORTH

The Green Energy and Green Economy Act ("GEGEA"), 2009, received royal assent on May 14, 2009, and amends and repeals various acts through legislation. The GEGEA includes a clause to facilitate consultation with and participation of Aboriginal Peoples in the development and implementation of renewable energy generation facilities and transmission and distribution systems. Consequently, the Ontario Power Authority, and various First Nations in Remotes' service territory are actively considering transmission connections to their communities. Remotes has assisted these discussions by providing information on load and costs.

In 2010, Section 48.1(1) of *the Electricity Act, 1998*, was amended to enable the government to require Remotes to distribute electricity within communities that are connected to the IESO-controlled grid and are prescribed by regulation. Accordingly, Remotes has been discussing the provision of service with the communities of Pikangikum and Cat Lake and has developed proposed rates for grid connected customers. Further information on the proposed Grid-connected rates can be found in Exhibit G, Tab 01 Schedule 02.

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.

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 Act* (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.

SUMMARY OF REMOTES POLICIES

1.0 INTRODUCTION

Hydro One Inc. has a number of 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 Inc. has reviewed and revised a number of policies and procedures since the Board's review of Remotes Revenue Requirements and Rates for 2009 (EB-2008-0232). These policies and procedures apply to all Hydro One Inc. subsidiaries, including Remotes. The more significant changes are listed in the following sections.

2.1 Employee Business Expense Policy - Travel, Meals & Hospitality

On September 14, 2009, the Government of Ontario issued a directive to named entities, including Hydro One Inc., requiring that the named entities adhere to the Ontario Public Service Travel, Meal and Hospitality Expense Directive ("Directive"). As a result, Hydro One's Employee Business Expense and Travel Policy ("Policy") has been revised to conform to the directive. There were amendments to the Policy which took effect November 13, 2009, and on April 1, 2010, as a result of revisions to the Directive.

2.2 Consultants and Professional Services Policy

On July 17, 2009, the Government of Ontario issued a directive to named entities, including Hydro One Inc., requiring that the named entities adhere to new rules governing consulting contracts effective June 17, 2009. As a result, Hydro One's Consultants & Professional Services Policy has been revised to conform to the directive. This policy specifies the requirements applying to the procurement and approval of Consulting and Professional Services, including competitive bidding, single sourcing, and extensions. In addition the policy specifies that Consulting and Professional Service providers are not entitled to bill for hospitality, food expenses or incidental cost

2.3 Adoption of U.S. Generally Accepted Accouting Principles (US GAAP)

Consistent with the exemptive relief provided by the Ontario Securities Commission allowing Hydro One Inc. to make its quarterly consolidated securities filings under US GAAP for the three-year period ending December 31, 2014, Remotes adopted US GAAP for external financial reporting effective January 1, 2012. In the EB-2011-0427 decision dated April 3, 2012, the Board approved Remotes' request to adopt US GAAP as its approved basis for regulatory accounting and reporting for its business.

Given the similarity between US GAAP and legacy Canadian GAAP, as defined in Part V of the Handbook of the Canadian Institute of Chartered Accountants, no accounting policy changes have occurred through the adoption of US GAAP in 2012 that affect either the 2012 or 2013 rate base or revenue requirement compared to Canadian GAAP. In its application to adopt US GAAP for rate-setting purposes (EB-2011-0427), Remotes requested that a symmetrical variance account be established to record the 2012 impact of differences between CGAAP and US GAAP. This was approved by the Board. As at the time of filing, no differential impacts had been recorded in this account.

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 2011 pertained to the 2012-2016 period. The results as they apply to 2013 (the test year) form the basis for the rate submission.

The typical annual business planning process consists of six stages:

1. Strategic direction and goals established;
2. Risk review and investment requirements;
3. Confirmation of strategic direction and goals with Hydro One Inc;
4. Development of economic outlook and forecast assumptions;
5. Development of plans and work programs; and
6. Approval by Hydro One Inc. Senior Management and Board of Directors.

The key dates applicable to the 2012-2016 planning cycle include:

Date	Action
February 2011	Strategic direction and goals reviewed and established
March 2011	Risk review and investment requirements
April 2011	Hydro One Inc. confirmation of strategic direction and goals
May 2011	Business plan instructions issued
June 2011	Development of work programs
November 2011	Hydro One Inc. Senior Management and Board approval of business plan
April 2012	Hydro One Inc. Board approval of updated business plan

1.1 Strategic Direction and Goals Established by Senior Management

Remotes' strategic direction and goals are reviewed and established by its CEO management team and are confirmed by Hydro One Inc. The strategic goals are used by planners as the business plan is being developed. Remotes' corporate vision and strategic objectives are shown in Exhibit A, Tab 4, Schedule 1.

1.2 Risk Review and Investment Requirements

Annually, required investments are determined based on asset condition, engine hours, load growth and external factors (AANDC funding, winter roads). Investments are then ranked against financial, operational, environmental, safety, regulatory and legal requirements and risks. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and takes into account levels of investment and associated risk mitigation against financial, operational, environmental, safety, regulatory and legal considerations. A final investment plan is then endorsed and confirmed by the Hydro One Inc. senior management team. The investment plan prepared during 2011 provides the basis for the 2013 plan.

1.3 Development of Economic Outlook and Planning Assumptions

To facilitate the preparation of the business plan, an economic outlook is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits. The assumptions used for the 2012 business plan are attached to this exhibit as Appendix A.

1.4 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 2013 Rate Application. At the end of this process, senior management provides direction as necessary in order to balance the various factors under consideration including legal requirements, customer service levels, rate impacts and impacts on 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, Schedule 1 respectively. Refer to Exhibit A, Tab 14, Schedule 2 for an overview of Remotes' project approval process.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, fuel, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan is reviewed by 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. The 2012-2013 Budget and Outlook was approved by the Board of Directors at its November 2011 meeting and the updated plan was approved by the Board of Directors at its April 2012 meeting.

APPENDIX A

2012 BUSINESS PLAN ASSUMPTIONS

1.0 INTRODUCTION

This appendix provides the costing assumptions underlying the Hydro One Inc.'s 2012-2016 Business Plan.

2.0 ECONOMICS

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 expenditures: food, housing transportation, furniture, clothing and recreation.

CPI-Ontario exhibits the inflationary environment in which Remotes operates. The CPI forecast is from HIS Global Insight April 2011 forecast.

	2012	2013
CPI – Ontario (%)	2.1	2.1

3.0 EXCHANGE RATE (CDN$ per US$)

The historic rates in Table 3 are the average exchange rates for 2009, 2010 and 2011 from the Bank of Canada. The exchange rate forecast for 2012 was based on the average of the 3-month out (December 2011) and 12 month out (September 2012) forecasts from September 2011 Consensus Forecasts and for 2013 and 2014 was based on the Global Insight June 2011 Long-Term Forecast and Analysis.

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Exchange Rate (CDN$ per US$)	1.142	1.030	0.989	0.984	1.034

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.

4.0 INTEREST RATES

Interest rate forecasts and existing debt are used to determine the cost of capital for Remotes as described in Exhibit B1, Tab1, Schedule 1. The table below contains Remotes' long term debt rate as issued to them from Hydro One Inc. on April 1, 1999 and refinanced in 2005.

	Cost Rate %
Third Party long-term debt	5.60

4.1 Long-Term Debt Rates

The 90-Day Banker's Acceptance Rate for 2012-2016 was prepared based upon the June 2011 Global Insight Forecast.

	2012	2013
90-Day Banker's Acceptance Rate (%)	1.50	3.74

Remotes' interest capitalized rates are based on U.S. GAAP.

Interest Capitalized – US GAAP	2012	2013
Interest Capitalized Remotes (%)	4.78	4.32

5.0 LABOUR ESCALATION

Note that the allowed financial impact of labour escalation is capped at 3.0% annually (this excludes the impact of changes in payroll burden costs) for each staff category (i.e. Society, PWU and MCP). If your subsidiary's labour escalation exceeds 3.0% in any staff category in any given year then reduction 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

A 2.5% economic increase effective April 1, 2012 is planned. The Society Collective Agreement is up for renegotiations for 2013. It is assumed economic increases will remain at 3.0% for the negotiated term for the 2012-2016 business plan term.

COLA provisions for 2010 were not triggered and there are COLA provisions in 2011 and 2012. At this time, the COLA provisions have not been triggered for the fourth year of the Society Collective agreement (April 1, 2011-March 31, 2012). If this COLA provision is triggered, it will mean that Salary Schedules will be adjusted to reflect the change above the trigger effective at the end of the applicable year.

Automatic annual salary progressions will occur (in addition to the economic increases above) until staff reaches the terminal step.

For staff hired prior to October 1, 2007, annual progressions will occur on October 1 of subsequent years or on date of appointment to a new Society represented position. For staff hired after October 1, 2007, annual progressions will occur on the anniversary of their hire date.

(b) PWU Staff

The Power Workers' Union Collective Agreement has reached a tentative agreement that dictates an economic increase of 3.0% for 2011 and 2012. Economic increases are assumed to remain at 3.0% for the negotiated 2012-2016 business plan term.

Step Progressions – past experience (i.e.2010) indicates that 19.24% of PWU staff is eligible to receive automated progressions annually. Progressions will result in an average salary increase of 3.55%.

(c) MCP Staff

It is anticipated that a 3% annual increase per year in base pay for the 2012 year and 3% annual increase for the 2013-2016 period.

(d) Incentive Plan Payouts

All incentive plans have been discontinued, with exception of the MCP Short Term Incentive Plan. Payout under this plan is assumed to be 20% in all years.

6.0 INCOME & CAPITAL TAX RATES

	2012	2013
Federal Tax Rate	15.00%	15.00%
Provincial Rate	11.50%	11.50%
Total Statutory Tax Rate	26.50%	26.50%
Capital Tax Rate	NIL	NIL

7.0 BENEFIT COSTS RATES (PAYROLL BURDEN)

Company	Category	2012	2013
Remotes	Non-Regular Staff		
	% of total earnings*	5.69%	5.78%
	Regular Staff		
	% of total earnings*	5.69%	5.78%
	% of base pensionable earnings**	24.79%	24.13%
	Pension		
	% of base pensionable earnings	29.29%	28.87%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, Ontario Health Premiums (OHP), OPRB - Inergi
- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.

PROJECT AND PROGRAM APPROVAL & CONTROL

1.0 INTRODUCTION

As described in Exhibit A, Tab 14, Schedule 1, there are a number of key steps within the overall business planning cycle that are typically completed prior to the development of the detailed project and program assessments. These prerequisite steps include needs identification, project/program prioritization and the development of preliminary work programs, based on estimates of project and program costs and benefits.

2.0 PROJECT AND PROGRAM APPROVAL

Once the preliminary plans have been accepted at the proof-of-concept stage, an analysis of costs, proposed accomplishments, benefits and risk is completed for each program and for individual projects.

For work programs of an ongoing nature (such as engine replacements), the analysis associated with each program are included in Asset Planning Documents for review and approval. Programs are reviewed annually, considering factors such as regulatory requirements, business efficiencies, impacts on customers, reliability, environment and safety along with any other relevant information. For specific improvement and facilities projects business cases are only completed during the detailed budgeting process in November of each year, when specific project scope can be determined.

For projects that are not routine and do not occur annually, Business Case Summaries (BCS) for individual project proposals are developed and assessed. Similar analysis is undertaken for these projects, but in more detail than for routine work. Factors such as the need for the investment including the implications of not doing the work, the anticipated results and the recommended solution and its cost are all considered. In determining the recommended solution, alternative approaches and project risks are considered. The factors considered include regulatory requirements, business efficiencies, impacts on customers, reliability, environment and safety and any other relevant information. The proposals are reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved consistent with the provisions of the Organizational Authority Register ("OAR"), described in Exhibit A, Tab 9, Schedule 2. For programs, this analysis and approval is completed as part of the investment planning process. Strategic investments are reviewed and approved by the Hydro One Board of Directors. The BCS documents provided in Exhibit D2, Tab 2, Schedule 3 summarize the proposed projects and programs with expenditures exceeding $261 thousand in the test year.

3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures and work accomplishments. Deviations from plan are identified and corrective action taken.

In the event that significant changes in cost, schedule and/or scope of a project is forecasted, an Interim Review of Variance ("IROV") is prepared. An IROV is essentially an amended business case that is reviewed and approved based on the revised set of circumstances (cost, scope and schedule). The IROV approval is in accordance with the limits set out in the Organizational Authority Register (OAR). Projects which cannot be re-justified are either scaled back, cancelled or otherwise adjusted to conform to the new situation.

SERVICE QUALITY INDICATORS

1.0 INTRODUCTION

Subject to the exceptions and modifications noted below, Remotes currently monitors and records service quality indicators as required in Chapter 15 of the *Ontario Energy Board 2006 Electricity Distribution Rate Handbook*.

2.0 CUSTOMER SERVICE INDICATORS

The Customer service indicators that Remotes uses are as follows:

Connection of New Services:
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 as described above.

Emergency Response:
The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for Rural utilities. The elapsed time is measured from the call to the arrival of qualified Remotes' service personnel, and includes Remotes' agents.

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.

Table 1 shows the customer service results for the historic years.

Table 1
Customer Service Indicators

Performance Measure	**OEB Target**	**2009 Actual**	**2010 Actual**	**2011 Actual**
Connection of New Services (% completed in ≤ 5 days)	**≥ 90**	**100**	**100**	**100**
Emergency Response (% responded to in ≤ 120 min)	**≥ 80**	**92.3**	**97.8**	**96.6**
Written Response to Inquiries (% responded to in ≤ 10 days)	**≥ 80**	**100**	**100**	**100**

*Emergency Response results including the impact of Force Majeure.

Due to the distances between communities and the associated cost to transport staff and equipment, Remotes does not track several of the Service Quality Requirements (SQRs) as identified by the OEB as reporting requirements. For example, Remotes is not able to track the SQRs related to Appointment Scheduling, and Appointments Met and Rescheduling of Missed after January 1, 2009. Remotes phone system cannot track call abandon rates or the time to answer calls. As a result, Remotes is not able to track the SQR related to telephony.

Remotes' distribution system consists primarily of overhead conductors. Underground cables are owned by the customer and locates are rarely required. Therefore Remotes has not established this measure as a monthly performance target.

With respect to the SQR for connections for new services, 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 these factors.

3.0 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 monthly, which are reported internally (see Section 2.2 for definitions).

Customer interruptions are analyzed and reported internally throughout the year. If the annual performance targets are met, the targets for the following year are established based on improvements to the 5-year average.

The three Service Reliability Indicators are as follows:

<u>System Average Interruption Frequency Index (SAIFI):</u>
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.

<u>System Average Interruption Duration Index (SAIDI):</u>
The average numbers of hours that customers served by Remotes were without power in the year.

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.

3.1 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.

4.0 RESULTS

Table 2 shows the service reliability over the periods 2009 to 2011 and the targets for 2012.

Table 2
Service Reliability Indicators

Performance Measure	2009 Target	2009 Act	2010 Target	2010 Act	2011 Target	2011 Act	2012 Target
SAIFI *Frequency of Interruptions* (#of interruptions per customer)	**≤ 15.6**	**11.5**	**≤ 12.0**	**8.1**	**≤ 12.0**	**7.8**	**≤ 11.7**
SAIDI *Duration of Interruptions* (hrs of interruption per customer)	**≤12.7**	**9.4**	**≤ 10.5**	**10.9**	**≤10.5**	**8.3**	**≤8.3**
CAIDI *Average Interruption Time* (#of hrs per interruption)	**≤ 0.8**	**0.8**	**≤ 0.9**	**1.3**	**≤ 0.8**	**1.1**	**≤0.9**

Over the historical period, SAIFI performance has been better than target. SAIDI has been relatively stable. Since CAIDI is dependent on both SAIDI and SAIFI (mathematically CAIDI = SAIDI / SAIFI), the reduction in the number of interruptions without a parallel reduction in the length of the outages can result in CAIDI being worse than target, as it was in 2010. There were no Force Majeures during the period of 2009 through 2011.

GREEN ENERGY PLAN

Remotes does not have a Green Energy Act Plan as defined in the filing Requirements: Distribution System Plans –Filing under Deemed Conditions of Licence: Revised May 17, 2012 (EB-2009-0397). The main reasons for this involve Remotes not being eligible for the OPA's FIT or MicroFIT programs as well as the very limited opportunity for renewable generation connection in its service territory as described below. Remotes is involved in numerous green energy activities, which are also described below.

Due to the lack of grid connection, Remotes generates 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. There are presently 57 diesel generators in service, ranging in size from 65kW to 1250kW. 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 also owns and operates two run-of-the-river mini-hydroelectric 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 will continue to offer technical assistance to the communities in reviewing opportunities through the Aboriginal Loan

Guarantee Program and the Aboriginal Community Energy Plan. Remotes would enter into power purchase agreements based on the avoided cost of diesel fuel to support these projects.

Remotes operates 19 isolated distribution systems to serve the 21 communities. Since 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. In total they include approximately 233 kilometers of line, 4610 wood poles, 1,122 transformers (used for voltage transformation) and 265 switches distributed throughout the system. Due to the technical complexity of controlling voltage and frequency in these isolated, off-grid, distribution systems, any potential for distributed generation is severely limited. Additionally, the development of renewable energy is limited by very small community loads and the lack of local water and wind resources, close to the communities.

As required in the filing Requirements: Distribution System Plans –Filing under Deemed Conditions of Licence: Revised May 17, 2012 (EB-2009-0397), Appendix A contains Remotes' August 13, 2012 letter to the OPA, requesting their review and comment on Remote's inability to develop and implement a Green Energy Plan. Appendix B contains OPA's response, received on August 30, 2012.

LETTER TO OPA REGARDING THE REMOTES GREEN ENERGY ACT PLAN

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Ruth Greey
Senior Regulatory Advisor
Regulatory Affairs

BY COURIER

Monday, August13, 2012

Ms. Nancy Marconi
Ontario Power Authority
Manager, Regulatory Proceedings
120 Adelaide Street West
Suite 1600
Toronto, ON
M5H 1T1

Nancy,

Dear ~~Ms Marconi~~:

Subject: Hydro One Remote Communities Inc.'s Green Energy Act Plan

Hydro One Remote Communities Inc. ("Remotes") is submitting its 2013 Cost of Service Revenue Requirement Rates Application to the Ontario Energy Board, around September 7th, 2012. As you know Remotes is not eligible for the FIT or MicroFIT programs. There is also very limited opportunity for renewable generation connection in Remotes service territory and as such Remotes does not have a Green Energy Act Plan as defined in the filing Requirements: Distribution System Plans –Filing under Deemed Conditions of Licence: Revised May 17, 2012 (EB-2009-0397). Please review the attached information that describes Remotes generation and distribution systems and the associated green energy activities. Remotes would appreciate your acknowledgement of this letter as well as any comments you may have regarding the Remotes green energy activities.

Yours truly,

Ruth E Greey

Ruth Greey

Cc: Una O'Reilly
Allan Cowan

Attach.

Hydro One Remote Communities Inc. Green Energy Activities

Due to the lack of grid connection, Remotes generates 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. There are presently 57 diesel generators in service, ranging in size from 65kW to 1250kW. 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.

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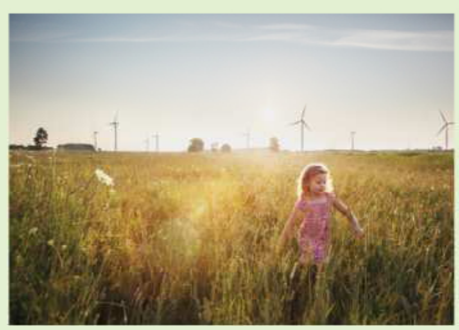
OPA LETTER OF COMMENT: BASIC GREEN ENERGY ACT PLAN

Appendix B



OPA Letter of Comment:

Hydro One Remote Communities Inc.

Basic Green Energy Act Plan

July 30, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Hydro One Remote Communities Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Hydro One Remote Communities Inc. ("Remotes") dated August, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

Remotes' GEA Plan indicates that there are no microFIT or FIT connection opportunities to date. The communities served by remotes are not connected to the IESO controlled grid and thus are not eligible for microFIT and FIT.

To date, the OPA has not received any applications from any communities served by Remotes.

Upstream Transmission Constraints

As Remotes is not connected to the IESO controlled grid, there are no transmission constraints applicable to Remotes' system.

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring communities at this time.

Conclusion

The OPA finds that Remotes' GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on the Basic GEA Plan provided by Hydro One Remote Communities Inc.

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PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

LIST OF WITNESSES

CURRICULUM VITAE

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 2013 test year.

2.0 CAPITAL STRUCTURE

Consistent with the Board's Decision in RP-1998-0001 and subsequent Decisions, 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 $16.4 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 the average spread as determined through a Board staff survey of real market quotes from major banks each January 1[1]. For Remotes, the deemed short-term rate is 2.01%, using the February 2012 Global Insight Forecast plus a spread of 91 bps, which is based on the spread contained in the Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012, dated November 10,

[1] The Board indicated in Appendix D of the December 11, 2009 Cost of Capital Report that, once a year, in January, Board staff will obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates to calculate an average spread.

2011. Remotes assumes that the deemed short term debt rate will be updated in accordance with the Board's December 11, 2009, Cost of Capital Report upon the final decision in this case.

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 $16,446 thousand in 2013 reflects the remaining amount of debt required to balance the total financing with the rate base. In its Decision in EB-2008-0232, the Board indicated that, "For companies with embedded debt, it is the cost of this embedded debt which should be applied to any additional notional (or deemed) debt that is required to balance the capital structure." Accordingly, the deemed long-term debt is calculated at 5.60%.

6.0 COST OF CAPITAL SUMMARY

Remotes' 2013 rate base is $41,090 thousand which results in a weighted cost on rate base of 5.46%, as shown in table below.

2013 Cost of Capital

Particulars	($000s)	% Of Rate Base	Cost Rate (%)	Weighted Cost Rate %	Cost of Capital ($000)
Deemed short-term debt	1,644	4.0%	2.01%	0.08%	33
Third Party long-term debt	23,000	56.0%	5.60%	3.14%	1,288
Deemed long-term debt	16,446	40.0%	5.60%	2.24%	921
Total	41,090	100%		5.46%	$2,242

The historical debt summary schedules have been provided at Exhibit B2, Tab 1, Schedule 1.

HYDRO ONE REMOTE COMMUNITIES INC.
Cost of Long-Term Debt
Test Year (2013)
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	5.6%

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 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 14, Schedule 1.

1.1 Operation, Maintenance and Administration Expenses (OM&A)

Total OM&A expenses for the 2013 test year are $44,199 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	2013 Total Cost ($000s)	Reference
Summary of OM&A Expenses	**$44,199**	**Exhibit C1, Tab 2, Sch 1**
Generation	$36,632	Exhibit C1, Tab 2, Sch 2
Distribution	$3,580	Exhibit C1, Tab 2, Sch 3
Customer Care	$1,903	Exhibit C1, Tab 2, Sch 4
Community Relations	$866	Exhibit C1, Tab 2, Sch 5
Shared Services and Other Administrative Costs	$1,157	Exhibit C1, Tab 2, Sch 6
External Costs	$61	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* (Updated June 28, 2012), 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 2, Schedule 1 and Exhibit C2, Tab 3, Schedule 1 presents 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 Hydro One Inc. subsidiaries, including Remotes, on a centralized and shared basis. The costs of these services and assets are assigned to business units on the basis of cost causation and benefit. 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 (since acquired by Black and Veatch) to establish a cost allocation approach for Common Corporate Functions and Services (CCFS) Costs, that would be in accordance with accepted industry standards. The CCFS Allocation Study determined an appropriate allocation of these shared services costs between each of the regulated and unregulated business units of Hydro One Inc. The study and its methodologies were accepted by the OEB in its Distribution Decision with Reasons dated April 12, 2006. The original study has since been refreshed for various regulatory applications, most recently for Networks' 2013/2014 Transmission application (EB-2012-0031, Ex. C1, Tab 7, Schedule 1, Attachment 1). The evidence included herein on the allocation of common corporate costs uses this methodology and is shown in Exhibit C1, Tab 6, Schedule 1. In addition, Black and Veatch has prepared a Review of Shared Assets Allocation for the Networks Transmission application (EB-2012-0031, Ex. C1, Tab 7, Schedule 3, Attachment 1). Given that Remotes uses the new enterprise-wide SAP system, it has been included in the scope of this study for the first time.

Exhibit D1, Tab 2, Schedule 1 provides evidence regarding the derivation of Overhead Capitalization Rates.

1.4 Depreciation and Amortization Expense

Remotes engaged Foster Associates Inc. to undertake a depreciation rate study for its assets. The results of this study form the basis of the depreciation submission in this application. The company is proposing to recover $6,030 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 ($187) thousand appears at Exhibit C2, Tab 5, 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 14, Schedule 1.

The proposed OM&A programs are required to meet public and employee safety objectives, to comply with regulatory requirements 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 by 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
	2009	2010	2011	2012	2013
Generation	26,153	31,078	33,158	34,455	36,632
Distribution	1,378	1,824	1,344	1,902	3,580
Customer Care	778	856	1,734	1,727	1,903
Community Relations	394	309	444	846	866
Shared Services and Other Administrative Costs	1,266	1,087	994	1,042	1,157
External Costs	156	172	129	61	61
TOTAL	30,125	35,326	37,803	40,033	44,199

Total OM&A expenditures are expected to increase by 10% or $4,166 thousand over the 2012 to 2013 period. Increases are driven by the purchase of transmission supplied electricity and the growth in distribution maintenance necessary to serve two new grid-connected communities, Pikangikum and Cat Lake in 2013, as well as the cost of diesel fuel which increases by 1,203 thousand in 2013.

Detailed descriptions of the work activities in each area of Remotes' OM&A expense and the reasons for the changes in costs over the 2009 to 2013 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. 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, the 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 SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS

The Shared Services and Other Administrative 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 57 diesel generators in service, ranging in size from 65kW to 1250kW. 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 $36,632 thousand and include $24,067 thousand for diesel fuel required to generate electricity. These expenditures are required 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
	2009	2010	2011	2012	2013
Generation Maintenance	4,277	5,917	6,558	7,145	6,012
Generation Operations	3,517	4,404	4,438	4,446	4,573
Fuel	18,359	20,757	22,162	22,864	24,067
Power Purchased	0	0	0	0	1,980
Total	26,153	31,078	33,158	34,455	36,632

3.0 GENERATION MAINTENANCE

Generation maintenance includes planned and unplanned maintenance related to the generation site, buildings, engines, systems and fuel storage and fuel systems. Planned maintenance prevents premature equipment and system failures and contributes to service reliability. Unplanned maintenance includes maintenance and repair related to trouble reports and equipment or component failures.

As outlined in Exhibit A, Tab 3, Schedule 1, AANDC informed Remotes that it is facing funding constraints and does not have funding for required upgrades in its then current 5-year capital plan. Delays to required upgrades have increased generating maintenance and operations costs over 2009 levels as generation assets and facilities are aging and increased maintenance is required since systems and plant are approaching end of life.

3.1 Maintenance of Diesel Engines

Planned maintenance of diesel engines is prescribed by the engine manufacturer and is required to keep generating units available and operating to meet community load. Intensive maintenance procedures are scheduled based on engine hours and vary from year to year. Forecasts of planned maintenance engines are based on forecast engine hours. Planned maintenance occurs based on actual engine hours. Regular maintenance is also performed on the run-of-the-river hydro stations. Forecast planned engine maintenance expense is based on a forecast of engine hours. Actual engine maintenance performed varies according to actual load in the community and the hours each engine is picked to run by the automated control system.

3.2 Maintenance of Plant and Auxiliary Systems

Planned maintenance of plant and auxiliary systems includes inspection and maintenance of all electrical system and SCADA systems; inspection and maintenance of secondary heating, primary cooling and ventilation systems; inspection and maintenance of overhead cranes; and annual inspection and maintenance of fire suppression systems.

Most of our fire suppression systems are over 10 years old and were installed when stations were newly constructed. Delays in upgrade funding will mean that these systems will continue to age and increased maintenance will be required. A comprehensive one-time program to inspect and repair fire suppression systems and to replace cylinders of fire suppressant was started in 2010. Work in 2010 and 2011 identified risks associated with fires in our fuel systems and the need for an ongoing program to meet regulatory requirements for annual certification of fire systems, to ensure that the equipment is in full operating condition and to avoid catastrophic failure by limiting damage to our plants in case of a fire.

Remotes has adapted to the inaccessibility of its service territory by adopting innovative new electrical and SCADA systems in our plants. This significant shift in technology has also helped improve safety, environmental performance and fuel efficiency. For example, changes associated with automation resulted in a 10% improvement in fuel efficiency and further innovation by engine manufacturers promise even greater improvements. As plants become electronically based, the requirement to test, inspect, calibrate and troubleshoot of auxiliary equipment increases and becomes more complex.

3.3 Maintenance of Buildings

Planned maintenance related to structures includes 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. Delays to planned upgrades have increased the required civil repair work significantly as buildings that were expected to be replaced age and require increased maintenance.

3.4 Maintenance of Tank Farms

Planned maintenance of tank farms includes expenditures required to inspect, maintain and address deficiencies in the generating station fuel offload, bulk storage tanks and fuel transfer equipment in order to keep fuel systems in standard operating condition. Fuel system maintenance is directly related to Remotes' responsibility for station operation as prescribed in the Electrification Agreements and Fuel Oil Regulation 212.

3.5 Design, Construction and Asset Management (Engineering) Support

Design, Construction and Asset Management maintenance programs and projects are related to improvements in the efficiency, safety and operation of generation assets and include engineering investigations, electrical drawing projects and renewable energy improvements.

Table 2
Generation Maintenance OM&A
($000s)

Category	Historic			Bridge	Test
	2009	2010	2011	2012	2013
Generation Maintenance	4,277	5,917	6,558	7,145	6,012

Increases in generation maintenance between 2009 and 2010 are related to higher unplanned maintenance of engines ($500 thousand), higher maintenance of auxiliary and plant systems ($835 thousand), buildings ($244 thousand) and renewable energy maintenance ($112 thousand).

Increases in generation maintenance between 2010 and 2011 are related to higher planned maintenance of engines ($109 thousand), higher plant maintenance of auxiliaries and plant systems ($300 thousand), higher renewable energy maintenance ($123 thousand) and road maintenance to the Shoulderblade Falls site at Deer Lake ($300 thousand), and expenditures related to electrical station drawings associated with station standards and the new station in Webequie ($314 thousand) are offset by lower unplanned engine maintenance in 2010 (-$525 thousand) and lower planned maintenance of buildings (-$89 thousand).

Increases in generation maintenance between 2011 and 2012 are related to higher planned maintenance of engines ($240 thousand), higher unplanned maintenance of engines ($256 thousand), higher planned maintenance of buildings ($220 thousand), increases associated with efficiency improvements to existing renewable energy assets ($166 thousand) and a battery survey initiated to investigate batteries and chargers after a battery failure at Sandy Lake ($166 thousand). These increases are offset by decreased plant maintenance auxiliaries and systems ($362 thousand).

Decreases in generation maintenance between 2012 and 2013 are associated with lower planned maintenance of buildings (-$173 thousand), lower engineering investigations (-$279 thousand), lower planned maintenance of renewable energy (-$148 thousand), lower expenses associated with efficiency improvements to existing renewable energy assets (-$151 thousand) and fewer station electrical drawing projects (-$230 thousand).

4.0 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.

The inaccessibility of its service territory is Remotes' greatest operational risk. Within each community, Remotes contracts for local operators, who perform regular routine inspection and maintenance 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 safe handling, transportation and disposal of waste. Operators are also responsible for keeping the stations clean, undertaking filter changes, checking diesel plants and reporting and troubleshooting problems to the Thunder Bay Service Centre. Operators are also responsible for responding to emergencies such as power outages, house fires and spills. Over the past two years, Remotes has increased the number of agents in most communities to ensure that qualified personnel are available on site.

Operations staff in Thunder Bay is responsible for ensuring that the diesel plants operate safely and reliably. Operations staff is also the primary contacts for the operators, responsible for supervising and scheduling, developing plant-specific procedures, logistical and troubleshooting support, assisting the operator in emergency response, plant reporting and for ensuring that the operators are competent to perform daily maintenance activities. Operations staff is responsible for conducting and documenting operator training. Each operator must successfully complete a comprehensive on-site training program each year. On average, each operator requires annual training of two weeks to learn to operate the plant systems, respond to emergencies and perform day-to-day maintenance.

Generation operations also include a variety of environmental programs. These programs are conducted to ensure that Remotes complies 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. The EMS requires regular audits, spills prevention, support and training for staff and agents, and internal and public communications.

Generation operations, excluding fuel and power purchases, in the historic, bridge and test years are presented in Table 3 below.

Table 3
Generation Maintenance OM&A
($000s)

Category	**Historic**			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Generation Operations	3,517	4,404	4,438	4,446	4,573

Increases in generation operations between 2009 and 2010 relate to expenses associated with the clean-up, investigation and monitoring of a large fuel spill at the Kasabonika Lake station ($572 thousand) and the addition of Marten Falls to Remotes' service territory ($200 thousand).

5.0 FORECAST OF FUEL USAGE, PRICING AND DELIVERY

Fuel purchases for the historic, bridge and test years are shown in Table 4 below.

Table 4
Fuel Purchases
($000s)

Category	**Historic**			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Fuel	18,359	20,757	22,162	22,864	24,067

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 RRRP Variance Account. The load forecast methodology is discussed in more detail in Exhibit G1, Tab 1, Schedule 2.

5.1 Fuel Usage Forecast

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 going-forward basis using average load growth, historical customer growth patterns and seasonality. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads.

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.

Expected fuel commodity prices are based on market prices at the time the forecast is made. Fuel commodity prices are escalated based on CPI. As there is no Canadian forecast for diesel fuel commodity prices, commodity pricing is confirmed through a high level analysis of the published fuel indices that are used by each supplier.

The cost of delivery accounts for about 45% of the delivered price of fuel. As a result, supply delivery contract data is critical in developing the forecast costs. Supplier contracts are subject to a competitive tendering process and delivery costs are forecast on the basis of supplier contracts and historical deliveries of winter road fuel. Air delivery typically constitutes about 70% of fuel delivered to Remotes' communities, followed by all-weather road delivery at 13%, winter road delivery at 12% and First Nation contracts at about 5%.

Table 5
Total Cost of Fuel

Fuel Efficiency (kWh/litre)	3.72
Total litres of fuel issued (000's)	15,668
Average delivered cost per litre ($)	1.536
Total Cost of Fuel (000's)	24,067

5.2 Fuel Cost Management

Overall fuel costs are affected by three main factors: price, volume and delivery. Two of these factors can be influenced by Remotes (volume and costs of delivery), and Remotes has several initiatives underway to address volume. To influence fuel volumes, Remotes has introduced a customer demand management program and has been making engine and station efficiency improvements.

Remotes has also taken steps to reduce delivery costs, by increased use of winter road deliveries when available, and has improved supplier contracts that give Remotes access to competitive delivery contracts. In 2007, a comprehensive tender process was used to establish contracts for fuel supply and delivery. The competitive process established a larger network of suppliers than had previously been available, reducing overall delivery costs. In 2010, the competitive process was further refined by improving pricing parameters for fuel delivery over winter roads. In 2011, Remotes expanded its contracting with local First Nations to try to increase the purchase of winter road fuel from First Nation-owned tank farms in 2012 (unfortunately, the poor winter roads in 2012 resulted in lower than expected deliveries). 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, discussed in Exhibit C1 Tab 2, Schedule 5

- 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
- Maximized winter road deliveries (cheaper delivery methods) where possible through supplier relationships and improved tank storage
- Negotiated an increased number of fuel contracts directly with the First Nation communities with fuel storage on site where Remotes does not have adequate fuel storage facilities to take advantage of winter road delivery pricing.

6.0 POWER PURCHASES

6.1 Transfer of Shoulderblade Falls Hydroelectric Station

During the 1990s, Ontario Hydro, Deer Lake First Nation and AANDC jointly funded the construction of a small hydroelectric station at Shoulderblade Falls as a demonstration of renewable technology in the north. In 1999, Deer Lake and Ontario Hydro agreed that Ontario Hydro would operate the station for 10 years and then would transfer ownership to Deer Lake at the end of 2009. Ontario Hydro agreed to pay Deer Lake for purchased power based on the avoided cost of diesel fuel. Remotes inherited this agreement from Ontario Hydro. At the request of Deer Lake First Nation, the transfer of the station was deferred until the end of 2012. Starting in 2013, it is anticipated that Remotes will begin purchasing power from Deer Lake First Nation. Power purchases are expected to be lower than the cost of diesel fuel based on the original agreement.

Table 6
Shoulderblade Falls Power Purchases

Total MWh purchased	1,881
Estimated Cost of Power (000's)	$612

6.2 Forecast Power Purchases for Grid Connected Communities

As discussed in Exhibit A, Tab 4, Schedule 1, Remotes expects to begin serving the communities of Cat Lake and Pikangikum in 2013. As detailed historical information about the load in these communities is not available, estimated load is based on best available information, and by comparing the communities to similar sized communities served by Remotes.

Table 7
Forecast Purchases by Community
MWh

	Historic			Bridge	Test
Community	**2009**	**2010**	**2011**	**2012**	**2013**
Cat Lake	0	0	0	0	1,921
Pikangikum	0	0	0	0	10,682
Total (includes line losses)	0	0	0	0	12,603
Total Cost of Power (000's)	0	0	0	0	$1,368

A detailed discussion of Remotes' estimate of the per kWh cost of power purchased through the transmission grid can be found in Exhibit G1, Tab 1, Schedule 2.

DISTRIBUTION OM&A

1.0 INTRODUCTION

Remotes served approximately 3,500 customers at the end of 2011 through 19 isolated distribution systems to serve 21 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 233 kilometers of line and transformers distributed throughout the system, which are used for voltage transformation.

The proposed OM&A expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability and also reflect, starting in 2013, the inclusion of Cat Lake and Pikangikum in Remotes' service territory. 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**
	2009	**2010**	**2011**	**2012**	**2013**
Distribution Maintenance	1,003	1,729	1,232	1,608	3,279
Distribution Operations	375	95	112	294	301
Total	1,378	1,824	1,344	1,902	3,580

Distribution maintenance includes 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 equipment maintenance that is primarily cyclical in nature, including maintenance of equipment (line reclosers and line regulators).

Distribution maintenance also includes costs associated with metering. 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. Based on Measurement Canada rules, meters must regularly 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 overbilled nor underbilled.

Distribution operations includes data collection and system condition assessment used to plan corrective and preventative maintenance, joint use activities and engineering support for distribution. The Distribution System Code requires that all local distribution companies assess the condition of its assets and 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.

Lower distribution operations in 2010 compared to 2009 primarily reflect lower data collection activities as part of Remotes' program to assess the condition of its distribution assets. Increased distribution operations in 2012 reflect increased engineering support for distribution and the completion of a project to automate data collection. Higher maintenance activities in 2010 compared to 2009 reflects increased trouble response, planned maintenance and forestry. Lower distribution maintenance in 2011 compared to 2010 reflects lower forestry (-$261 thousand), reduced trouble response -($221 thousand) and lower planned maintenance (-$63 thousand). Expected increases in 2012 compared to 2011 primarily reflect higher trouble response ($235 thousand) and higher forestry services ($194 thousand). Increases between 2012 and 2013 reflect increased trouble response ($180 thousand), higher planned maintenance ($111 thousand) and higher forestry services (1,200 thousand) mainly associated with clearing the transmission line right-of-way to Cat Lake and costs associated with service to Pikangikum ($380 thousand).

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
	2009	2010	2011	2012	2013
Customer Care	1,143	1,480	1,930	1,689	1,855
Bad Debt	(365)	(624)	(196)	38	48
Total	778	856	1,734	1,727	1,903

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 2011 was higher mainly due to participation on the corporate project to replace Hydro One's billing system ($333 thousand). Bridge year spending is expected to be lower as the billing system project is implemented and required involvement in the project design winds down. Increases in 2013 relate to the inclusion of Cat Lake and Pikangikum in Remotes' service territory.

3.0 BAD DEBT

Bad debt expense is made up of direct writeoffs offset by recoveries, plus adjustments to the provision for bad debts. 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. The provision is an allowance taken against receivables where full recovery is in doubt and is determined using allowance rates on previous actual payment history, the normal payment curve and specific adjustments for large or unusual receivables based on management judgment. Adjustments to this allowance are charged to bad debt expense when outstanding receivables increase. When outstanding balances are reduced, the provision is reduced and the adjustments are credited to bad debts.

Credits to bad debt expense in 2009, 2010 and 2011 reflect Remotes' success in negotiating payment arrangements with First Nation Band Councils. Since January 2009, outstanding First Nation accounts receivable have been reduced from $9,532 thousand to $4,685 thousand in January 2012, when most First Nations had successfully completed their payment plans. As a result of these successful payment arrangements, the provision has been reduced. Bad debt expense is expected to increase to reflect the conclusion of most of these payment plans in the bridge and test years.

COMMUNITY RELATIONS OPERATIONS, MAINTENANCE AND ADMINISTRATION

Table 1
Community Relations
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Total	394	309	444	846	866

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.

CDM is the largest element of Remotes' Community Relations activities. Funding for CDM ($300 thousand) was first approved as part of its ongoing revenue requirement in its 2005 rate application (RP-2005-0020/EB-2005-0497) and the same level of funding ($300 thousand) was approved in its 2008 application (EB-2008-0232). Remotes believes that an expansion of this program is a key aspect of meeting customer energy requirements going forward. Remotes' energy conservation activities involve 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. Conservation of energy assists customers in managing their electricity bills and also reduces Remotes' fuel usage.

Remotes' current customer conservation program is designed to develop sustainable conservation by developing local expertise and buy-in within communities. Remotes' program focuses on conservation and energy efficiency awareness and on deploying energy efficient appliances within these communities. As part of this program, Remotes hires and trains a local coordinator to implement energy efficiency measures and to educate community members about energy use. Remotes includes three communities a year in this program and expects that eventually each community will have participated in the program.

In 2011, Remotes initiated an ongoing partnership with the Northern stores to offer rebates on ENERGY STAR appliances. This initiative promises to lead to long term energy savings and will help make energy efficient appliances available throughout Remotes' service territory and extends energy conservation activities to communities that are not part of the intensive pilot program.

In 2011, Remotes' customer conservation programs resulted in 245,600 kWh of in-year savings and life cycle savings of 1,891,878 kWh.

Although the Ontario Power Authority (OPA) is working to develop a program within Remotes' service territory, its program is not yet available. Remotes has worked with the OPA on various initiatives in the north, including conservation and transmission planning and expects that its efforts to deploy conservation programming in the north and will support and dovetail with the OPA programs when they become available.

Due to federal funding constraints, AANDC does not have funding for needed upgrades in its five-year capital plan. To help alleviate the need for increased generation related to load growth, Remotes plans to expand its conservation activities in 2012 and 2013 (2012 $344 thousand, 2013 $361 thousand). Planned activities include more work with First Nation Band Councils to conserve electricity used in band operated assets such as Band Offices, arenas and water and sewage plants. Remotes also plans to work with communities and with Canada Mortgage and Housing to ensure that energy efficient appliances are purchased when new homes are built and to ensure that energy efficiency standards are considered for new buildings.

Other Community Relations activities include Remotes' Customer Advisory Board ("CAB"), customer research activities, customer communications and community relations expenses such as community meetings. Remotes surveys its customers and Band Councils annually to discuss service satisfaction, planned program activities, areas that services can be improved and related matters. Customer communications includes bill inserts and other mailings to customers. Community relations activities include community meetings and other outreach activities to discuss service issues. CAB members are residential and commercial customers from within Remotes' service territory. The CAB offers advice on service policies and procedures, and on ways to improve services within the communities. Costs for this program are related primarily to meeting facilities, transportation to meetings and travel expenses for CAB members.

Variances between 2009 and 2010 relate to reduced spending on CDM ($97 thousand) as a result of difficulties retaining community coordinators. Variances between 2010 and 2011 relate primarily to conservation program activity returning to plan in 2011 ($101 thousand). Increases between 2011 and 2012 relate to planned increases in conservation program activities ($344 thousand).

SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS

1.0 SHARED SERVICES

Shared Services include common corporate functions and services (CCFS), telecommunications, enterprise technology, supply management services.

Table 1
Remotes' Shared Services
($000s)

Description	Historic			Bridge	Test
	2009	2010	2011	2012	2013
CCFS	891	1,009	952	893	905
Telecommunications Services	141	132	134	128	118
Enterprise Technology Services	333	375	331	226	222
Supply Management Services	60	79	77	77	77
Customer System Operations	45	46	48	49	48
Common Asset Allocation	0	0	0	0	180
Total	1,470	1,641	1,542	1,373	1,550

2.0 CCFS COST ALLOCATION METHODOLOGY

Hydro One Inc. has identified certain CCFS that provide common benefits to all business units while minimizing costly and unnecessary duplication. Since 2006, Hydro One Inc. has applied a cost allocation methodology developed by Black and Veatch (B&V) that is based on clearly articulated shared services and an established cost allocation approach based on cost causality and benefit principles. The principles-based allocation is based on direct allocation where possible and on activity-based drivers where it is not. Costs provided under the shared services model include CCFS (e.g. legal, finance and human resources), Telecommunications Services (telephone, fax and internet services for the Thunder Bay service centre and at each of the remote community sites); Enterprise Technology Services (outsourced services provided by Inergi LP related to IT systems, accounts payable, payroll, billing and financial IT systems and desk side support); Supply Management Services, and Customer System Operations (customer billing).

The shared service model allows for the delivery of specialized services without replicating these functions within each separate subsidiary. Benefits to Remotes include the following:

- Ensures availability of required specialist expertise and resources;
- Ensures application of consistent policies, governance frameworks, business processes;
- Rationalizes and offers consistent levels of service across all Hydro One subsidiaries irrespective of size (human resources, pay and financial services, infrastructure support);
- Uses common technology systems and platforms providing better access to high quality and accurate information and to required services; and
- Allows Remotes to benefit from economies of scale in such areas as accounts payable processing, procurement processes and management of supplier relationships.

CCFS are also discussed in Exhibit A-09-03, and include Corporate Management, Finance, Outsourcing Services, Internal Audit, Tax, Legal, Corporate Secretariat, Regulatory, Corporate Communications and Services, First Nation and Metis Relations, Security, Human Resources and Labour Relations.

In 2013, Remotes will begin being charged for its use of the SAP systems associated with the Cornerstone project ($180 thousand). This Common Asset Allocation is supported by a recent B&V Review of Shared Assets Allocation prepared for the Networks Transmission application (EB-2012-0031, Ex. C1, Tab 7, Schedule 3, Attachment 1). Given that Remotes uses the new enterprise-wide SAP system, it has been included in the scope of this study for the first time.

3.0 OTHER ADMINISTRATIVE COSTS

Other Administrative Costs include Remotes' project costs; Ontario Energy Board cost assessment, costs awards and proceeding-specific costs; and expenses related to the OEB's Low-Income Emergency Assistance Program.

Table 2
Other Administrative Costs
($000s)

Description	Historic			Bridge	Test
	2009	2010	2011	2012	2013
Regulatory and Project Expenses	262	0	79	140	140
Low-Income Energy Assistance Program (LEAP)	0	0	52	52	52
Total	262	0	131	192	192

Regulatory and Project Expenses include costs directly associated with Ontario Energy Board hearings on Remotes' matters and also include, starting in 2011, the Ontario Energy Board's allocation of its expenses to Remotes (approximately $80 thousand each year). Regulatory expenditures of $54 thousand in 2009 relate to Remotes' 2008 Cost of Service proceeding (EB-2008-237). Project expenses are associated with a corporate software project undertaken in 2009.

LEAP is an OEB directed initiative, which started in 2011.

4.0 TOTAL SHARED SERVICES AND OTHER ADMINISTRATION

Total Shared Services and Other Administration include credits associated with direct program assignments, non-energy bad debts and capitalized overheads.

Direct Program Assignments are services that can be directly assigned to an OM&A program, such as billing. These are deducted from Shared Services and Administration. Non-energy bad debts are also removed and are included in Customer Care, (Exhibit C1 Tab 2, Schedule 4).

Capitalized Overheads are the portion of Common Corporate Costs attributable to overhead and indirect costs related to capital projects that are capitalized, as discussed in Exhibit D, Schedule 2, Tab 1 and are deducted from Shared Services and Other Costs.

Table 3
Total Shared Services and Other Administrative Costs
($000s)

Description	**Historic**			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Shared Services	1,470	1,641	1,542	1,373	1,550
Other Administrative Costs	262	0	131	192	192
Total	1,732	1,641	1,673	1,565	1,742
Less Direct Program Assignments	(95)	(195)	(185)	(132)	(130)
Less Capitalized Overheads	(371)	(359)	(494)	(391)	(455)
Total Shared Services and Other Administration	1,266	1,087	994	1,042	1,157

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 (ESA) 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 from time to time in cooperation with AANDC and the local community. These assessments identify operational risks and efficiency measures that could be undertaken by AANDC 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. Lower external work in 2011 as compared to 2010 relates to the completion of site assessment work in the community of Weenusk ($46 thousand). Lower expected external work in 2012 and 2013 is primarily the result of lower projected ESA requests ($41 thousand).

Table 1
Costs Related to External, Unregulated Work
($000s)

Historic Years			Bridge	Test
2009	**2010**	**2011**	**2012**	**2013**
156	172	129	61	61

CORPORATE STAFFING

1.0 STAFFING STRATEGY AND OVERVIEW

Remotes' work is performed by regular staff, hiring hall staff, services purchased from Hydro One Networks Inc., contracts with external firms who provide 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. Over 40% of Remotes' work is performed by non-regular resources.

Remotes has 48 full-time, regular staff. Remotes' work program has increased significantly over the past four years. As outlined in Exhibits C1-02-02, C1-02-03 and D1-02-01, increases to the work program are driven primarily by the need to comply with environmental and safety regulation (Fire System Certification, Electrical Drawings for Plants, Operator Training) and by the need to supply safe and reliable electricity. A complement of regular, full-time staff is required to manage non-regular resources and to ensure that the work program can be completed. 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, regulatory support and services, customer outreach, contact and billing/collection services, program management, work execution, planning and management/supervision, skilled electrical and mechanical trades work and fuel and material inventory management.

Due to the nature of Remotes' service territory, extensive travel and time away from home may be required. Staff retention and recruitment can therefore be challenging. Additionally, about 40% of Remotes employees are eligible for an undiscounted retirement over the next five years. Remotes has a number of regular staff positions that are essentially “one of” positions. If an employee leaves the company to retire or pursue other opportunities, Remotes’ work program can be negatively affected until the job duties are mastered by the departing employee’s replacement.

To address the training risk associated with staff retirements, Remotes attempts to offer some overlap between new employees and retiring employees so that a skill transfer can take place. Remotes also participates in Hydro One Networks Inc. established recruitment, apprenticeship and training programs, and benefits from opportunities to employ skilled staff on a temporary basis (on rotations for example).

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 labour 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 also contracts with Hydro One Networks Inc. for various services. These contracts give Remotes access to a greater pool of employees than would otherwise be the case for a small utility. Remotes also secures 24 hour trouble response services, forestry services, purchasing services, legal services, information technology services, corporate accounting services, safety and work methods and training services from Hydro One Networks Inc. under Service Level Agreements. These agreements allow Remotes to supplement their regular staff and to access professional and trades staff required on a less than full-time basis. Additional resources used to supplement Remotes’ regular employees include casual skilled trades staff contracted through the Hiring Hall (Power Workers’ Union) and temporary staff.

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 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.

(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 C2 Tab 3 Schedule 1.

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 2013 test year.

The depreciation expense for Remotes' submission for the 2009 revenue requirement was based on the methodology in an independent study conducted by Foster Associates in 2006. Foster Associated completed a new Depreciation Study for Hydro One Remote Communities in support of this application. The study can be found at Exhibit C1-04-01 Attachment A.

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 the 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 4, Schedule 1.

2.0 DEPRECIATION EXPENSE

The aforementioned Foster methodology was used in determining the depreciation expense for the 2013 test year.

Table 1
Distribution Depreciation Expense
$ Thousand

Description	Historic			Bridge	Test
	2009	2010	2011	2012	2013
Depreciation On Fixed Assets	2,657	2,815	2,909	2,898	2,596
Asset Removal Costs	377	271	768	592	721
Losses/(Gains)	-	(112)	-	-	-
Total	3,034	2,974	3,677	3,490	3,317

The decrease in 2013 depreciation expense amount relative to the 2012 amount is due to the application of the depreciation rates recommended in the Depreciation Rate Review by Fosters Associates. The most significant changes in rates occur in the prime mover asset class.

Fixed asset removal costs are charged to depreciation expense on an "as incurred" basis. Removals increased significantly in 2011 due to a higher level of engine replacements and overhauls as well as a distribution line tear-down. In 2013 there are a greater number of engine replacements which results in increased removal costs.

3.0 AMORTIZATION EXPENSE

Remotes recognizes a liability for estimated future expenditures required to remediate past environmental contamination 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 2030. The Board accepted this accounting treatment as part of the RP-2008-0211 Decision. The treatment of these costs in this Submission is consistent with the treatment in that proceeding. Remotes reviews its estimates of future environmental expenditures on an ongoing basis.

Table 2
Remotes Amortization Expense
$ Thousand

Description	Historic			Bridge	Test
	2009	2010	2011	2012	2013
Environmental Assets	983	1,268	1,017	3,474	2,713

Table 2 shows historic bridge and test expenditures of Land Assessment Remediation (LAR). 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' sites is associated with historic spills of diesel fuel.

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. As these projects are normally undertaken with the involvement of the local First Nations, negotiations are required and project delays can occur. Increases in 2012 are associated with construction work at the old generating site in Sandy Lake, including bio-cell construction, excavation of impacted soil, haulage and backfilling, in-situ remediation system design, installation of extraction/injection wells and supply and installation of a groundwater pumping system ($1,700 thousand). In 2013, the decrease is attributable to the end of construction in Sandy Lake (-$ 1,960 thousand), offset by increases associated with the anticipated clean-up of historical contamination in Pikangikum ($600 thousand), the removal and remediation of an old tank farm site in Attawapiskat ($350 thousand), and the start of the clean-up of the old generating station in Webequie ($260 thousand).

DEPRECIATION STUDY

2011 Depreciation Rate Review

hydro one

Remote Communities, Inc.

foster associates

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EXECUTIVE SUMMARY

INTRODUCTION

This report presents a 2011 review and update of depreciation rates and parameters for Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) owned and operated by Hydro One Inc. (Hydro One). The review requested by the Company was conducted under the direction and supervision of Dr. Ronald E. White whose professional qualifications are provided in Section V.

Foster Associates is a public utility economic consulting firm headquartered in Rockville, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer applications for conducting depreciation and valuation studies.

PLANT ACCOUNT STRUCTURE

The hierarchical structure of plant accounting records maintained by the Company for major asset categories provides: a) Uniform System of Account (USoA) categories; b) cost of asset components (Profile ID); c) vintage identification (Asset ID); and d) property unit identification within vintages (CAT ID).

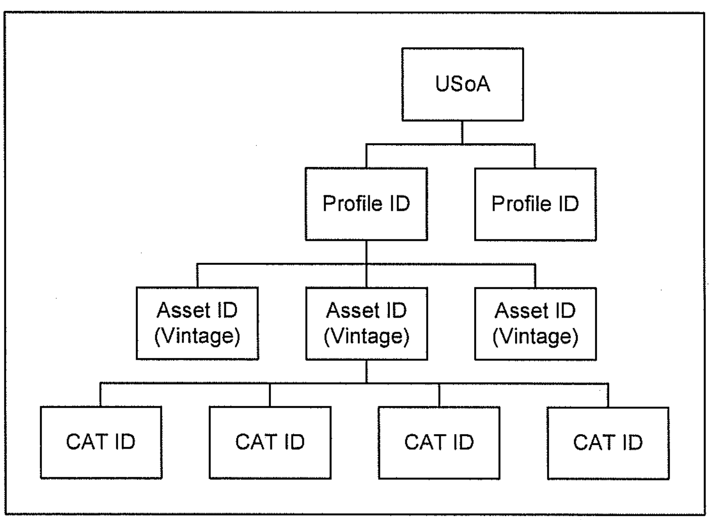

Fig. 1 Account Structure

The lowest level at which the installed cost of a property unit (*e.g.*, a single pole or transformer) can be estimated is by vintage year of placement within a Profile ID. (The cost of a property unit within a vintage can be estimated by dividing the vintage cost by the recorded number of installed property units). A Profile ID is an aggregation of vintage costs sharing common physical or functional attributes. All vintages of line transformers less than or equal to 230 KVA, for example, or all vintages of underground service conductors are classified in unique Profile IDs. It is neither practical nor feasible, however, to estimate service lives and maintain accumulated depreciation reserves for each property unit.

CURRENT DEPRECIATION RATES

Depreciation rates currently used by Hydro One Remote Communities were developed in a 2006 depreciation review conducted by Foster Associates.

Life tables were constructed in the 2006 review for each USoA plant account for which retirements were recorded over the period 2000–2005. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Absent the availability of sufficient retirement activity to conduct statistical service life studies, depreciation rates developed in the 2006 review were derived from a composite of parameters *(i.e.*, projection lives and projection curves) recommended by the former Ontario Hydro internal Depreciation Review Committee (DRC) for asset profiles contained in a USoA category. The dominant projection curve and dollar–weighted average projection life (rounded to the nearest integer) of the constituent asset profiles were selected to describe the forces of retirement acting upon a USoA plant account.[1]

2011 DEPRECIATION RATE REVIEW

[1]In 1954, by joint agreement of the Engineering, Operations and Comptroller's Division of Ontario Hydro, average service lives were estimated for each of the Company's various plant accounts. The estimated lives were based on engineering/financial judgment and information gathered regarding service lives used by other utilities. Statistical studies based on survivor curves were introduced in 1959 to further improve the estimation of life expectancies. The DRC was established in 1973 to provide formal engineering review for various classes of assets. The role of the committee was expanded in 1975 to include responsibility for recommending service lives and service costs (*i.e.*, provisions for fixed asset removal costs) of all assets. The DRC annually reviewed the service lives of all major facilities and a selection of plant components, with the objective of reviewing all plant components at least once every five years. DRC recommendations were based on factors such as operating experience, retirement history, engineering judgment, expected regular maintenance and system requirements. The DRC review process was discontinued by Hydro One in 1998.

The principal findings and recommendations of the Hydro One Remote Communities 2011 Depreciation Rate Review are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, and average remaining life. Statement E displays the computation of proposed USoA projection lives derived from recommended IFRS profile lives.

SCOPE OF REVIEW

Principal activities undertaken in the 2011 review included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One and Hydro One Remote Communities plant accounting and operations personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been adopted, the Company is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the intangible and general plant categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
1915	Office Furniture and Equipment	7 yrs.
1920	Computer Hardware - Minor	5 yrs.
1935	Stores Equipment	8 yrs.
1940	Tools, Shop and Garage Equipment	6 yrs.
1945	Measuring and Testing Equipment	5 yrs.
1960	Miscellaneous Equipment	5 yrs.

Table 1. Amortization Accounts

RECOMMENDED DEPRECIATION RATES

Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended for Hydro One Remote Communities.

	Accrual Rate			2011 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Generation	6.75%	5.07%	-1.68%	$2,195,319	$1,649,399	($545,920)
Transmission	3.39%	2.23%	-1.16%	202,453	133,405	(69,048)
General Plant	3.30%	2.67%	-0.63%	232,212	188,064	(44,148)
Total	5.77%	4.33%	-1.44%	$2,629,984	$1,970,868	($659,116)

Table 2. Hydro One Remote Communities

The composite accrual rate recommended for Hydro One Remote Communities is 4.33 percent. The current equivalent rate is 5.77 percent. The recommended change in the composite rate is a reduction of 1.44 percentage points.

A continued application of current rates would provide annualized depreciation expense of $2,629,984 compared with an annualized expense of $1,970,868 using the proposed rates. The resulting 2011 expense reduction is $659,116.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Remote Communities. The proposed rates are subject to approval by the Ontario Energy Board.

SCOPE

The steps involved in conducting the 2011 depreciation review can be grouped into four major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2011 review for Hydro One Remote Communities included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by the Company provides aged transactions for all plant accounts.

Prior to 1998, plant accounting records were maintained in a legacy Fixed Asset Management System (FAMS) developed by Ontario Hydro. FAMS was replaced with an SAP system in 1998. The SAP system was replaced with a PeopleSoft asset accounting system in 2000. The PeopleSoft system was configured with the asset profiles maintained in the SAP system and uploaded with age distributions of surviving plant at December 31, 1999.[2] The PeopleSoft system was replaced in August 2009 by an updated version of the SAP system.

Plant and reserve data used in conducting the 2011 depreciation review was assembled by Hydro One personnel and coded by Foster Associates. Plant accounting transactions recorded between January 1, 2008 and July 31, 2009 were extracted from the PeopleSoft system, coded and appended to the database used in conducting the 2008 update. Transactions recorded between August 1, 2009 and December 31, 2010 were extracted from the SAP system. An additional dataset of profile plant and reserve balances at December 31, 2010 was assembled and reconciled to aggregate USoA balances. (See Statement E).

Age distributions of surviving plant (*i.e.*, plant surviving by vintage year of placement) at December 31, 2010 were derived by Foster Associates from the vintaged plant transactions and reconciled to age distributions provided by Hydro One. The complexity of the process through which the database was compiled and mapped to USoA plant categories prevented Foster Associates from reconciling the database to any public reports of Hydro One. The integrity of the assembled database, however, was verified by Hydro One Remote Communities.

Life Analysis and Estimation

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

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[2]In 2003, Hydro One undertook a two–phase project to a) map asset profiles maintained in PeopleSoft to USoA plant account classifications; and b) align quantities maintained in a Power System Data Base (PSDB) to the re–mapped USoA account classifications. The PSDB provides property unit identification and quantities associated with investments maintained in PeopleSoft. Asset profiles maintained in SAP were not mapped to USoA plant account classifications. This limitation prohibited using pre–2000 plant accounting activity in the 2006 depreciation review.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was employed in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this review. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

As noted above, the database for Hydro One Remote Communities contains plant accounting transactions for activity years 2000–2010. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[3] A similar limitation applies to the database of Hydro One Remote Communities which contains minimal retirement activity during the available activity years. Retirements must be sufficiently distributed across vintages within these years in order to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each USoA plant account for which retirements were recorded over the period 2000–2010. Without exception, life tables

[3]Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

As was noted in the 2006 review, limitations in conducting life analyses were also imposed by vintage years "banded" by Hydro One in 1992 and again in 1998 when age distributions from a Fixed Asset Management System (FAMS) were uploaded to SAP. All pre–1950 vintages were assigned a vintage year of 1950. Plant installed between 1951 and 1955 was assigned a vintage year of 1955. Similarly, plant installed during the intervals 1956–1960, 1961–1965 and 1966–1970 were assigned vintage years 1960, 1965 and 1970, respectively. Although discontinued in 1971, the banding of pre–1970 vintages will continue to produce unreliable life indications until most of the earlier vintages have been retired from service.

Pending the availability of sufficient retirement activity to conduct service life studies, it is the opinion of Foster Associates that a composite of the parameters estimated for the asset profiles contained in a USoA account provides the best available estimate of service life statistics for the current depreciation review.

CLASS/CATEGORY SERVICE LIVES

Confronted with an inability to obtain meaningful service life indications from statistical analyses, attention was shifted in the 2011 review to the profile lives derived in preparing for the implementation of International Financial Reporting Standards (IFRS) in 2008. The motivation for estimating USoA service lives from asset profile service lives (now termed class/category in SAP) has been strengthened by a requirement that Canadian rate–regulated entities transition to IFRS no later than January 1, 2013. This requirement carries with it a set of accounting rules (IAS 16) that changes depreciation accounting for long–lived assets. For example, IAS 16 requires that property, plant and equipment assets be componentized into items of property; that depreciation be calculated at the item level; and the carrying amount (*i.e.* cost less accumulated depreciation) be "derecognized" on disposal or when no further economic benefits are expected from its use.[4]

The *Recognition Principle* of IAS 16 prescribes that the cost of an *item* of property, plant and equipment shall be recognized as an asset if, and only if: a) it is probable that future economic benefits associated with the item will flow to the

[4]Group depreciation accounting neither reports nor recognizes gains or losses resulting from the retirement of property units before or after the expiration of an estimated service life. Under–depreciation of property units retired earlier than predicted is offset by over–depreciation of property units remaining in service beyond the estimated average service life of a group. This treatment is consistent with the regulatory principle that opportunities should be preserved for the recovery of capital devoted to public service.

entity; and b) the cost of the item can be measured reliably. Importantly, IAS 16 does not prescribe the unit of measure for recognition, *i.e.*, what constitutes an item of property plant and equipment. Individually insignificant items may be aggregated and the Recognition Principle applied to the aggregated value.

Based on these principles and recognizing that a USoA category may include a greater diversity of plant items than contemplated under an item procedure, a Profile ID (or class/category) is considered to be an appropriate and practical aggregation of plant items under IAS 16. This level of aggregation means that service lives will be estimated by Profile ID and gains or losses will be computed for plant items retired prior to achieving an age equal to an applied service life.

The requirement to estimate item service lives at the class/category level for IFRS reporting strongly suggests that USoA lives used for US GAAP reporting should mirror Profile ID lives estimated for assets aggregated into USoA categories. This functional relationship was preserved in the 2011 review by adopting composited Profile ID lives estimated for each class/category as a surrogate for a USoA projection life (P–Life). Profile lives used in the computation of proposed depreciation rates were estimated by an internal project team assigned to review and update estimates previously developed by the DRC. Members of the review team included Hydro One and Hydro One Remote Communities engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates.

Unlike the item accounting procedure prescribed under IAS 16, group depreciations rates developed under US GAAP are formulated with recognition of retirement dispersion. This requirement was satisfied in the 2011 review by selecting an Iowa survivor curve considered descriptive of the forces of retirement acting upon each USoA category. Recommended survivor curves were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions. Proposed projection lives derived from harmonic weighting of the profile lives recommended by the project team are summarized in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for Hydro One Remote Communities at this time. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current review) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

With the exception of amortizable categories in which theoretical or computed reserves replace recorded reserves, all remaining reserves were redistributed by multiplying the calculated reserve for each USoA primary account by the ratio of the sum of recorded reserves to the sum of calculated reserves. The sum of redistributed reserves is, therefore, equal to the sum of recorded depreciation reserves before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for Hydro One Remote Communities on December 31, 2010. The recorded reserve was $20,185,154 or 44.3 percent of the depreciable plant investment. The corresponding computed reserve is $18,447,389 or 40.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $1,737,765 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2011 review were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. It is the opinion of Foster Associates that this system will remain appropriate for Hydro One Remote Communities, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected intangible and general support asset accounts is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for these rate categories relieves Hydro One Remote Communities of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval of the proposed amortization periods. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life statistics recommended for Hydro One Remote Communities. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2011 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2010.
- Statement D provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, and average remaining life.
- Statement E displays the computation of proposed USoA projection lives derived from recommended IFRS profile lives.

Current depreciation accruals shown on Statements B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by Hydro One Remote Communities for the mix of investments recorded on December 31, 2010. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio}}{\text{Remaining Life}}.$$

HYDRO ONE REMOTE COMMUNITIES

Statement A

Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
GENERATION PLANT							
1620 Buildings and Fixtures	42.57		1.81%	25.95		27.96%	2.78%
1665 Fuel Holders, Producers and Accessories	34.87		2.30%	26.30		27.08%	2.77%
1670 Prime Movers	3.02		12.89%	3.98		73.21%	6.73%
1675 Generators	26.15		2.61%	6.93		62.22%	5.45%
1680 Accessory Electric Equpment	33.30		2.32%	9.51		48.28%	5.44%
1685 Miscellaneous Power Plant Equipment	26.31		2.34%	19.74		23.18%	3.89%
Total Generation Plant			6.75%	8.71		53.04%	5.07%
DISTRIBUTION PLANT							
1805D Land - Depreciable	67.28		1.34%	37.28		27.86%	1.94%
1806 Land Rights	58.57		1.36%	78.83		23.18%	0.97%
1830 Poles, Towers and Fixtures	32.67		2.53%	44.99		19.75%	1.78%
1835 Overhead Conductors and Devices	32.36		2.53%	38.24		25.77%	1.94%
1845 Underground Conductors and Devices	12.69		5.06%	15.74		52.34%	3.03%
1850 Line Transformers	27.26		2.89%	29.92		28.00%	2.41%
1860 Meters	1.17		20.00%	13.16		13.43%	6.58%
Total Distribution Plant			3.39%	33.62		24.90%	2.23%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	30.50	-5.0%	2.58%	41.11		19.43%	1.96%
1955 Communication Equipment	3.50	-5.0%	15.78%	1.00		96.62%	3.38%
Total Depreciable			2.58%	41.11		19.67%	1.96%
Amortizable							
1915 Office Furniture and Equipment	← 7 Year Amortization →			← 7 Year Amortization →			14.29%
1920 Computer Hardware - Minor	1.97		20.00%	← 5 Year Amortization →			19.25%
1935 Stores Equipment	← 8 Year Amortization →			← 8 Year Amortization →			12.37%
1940 Tools, Shop and Garage Equipment			16.67%	← 6 Year Amortization →			16.67%
1945 Measurement and Testing Equipment	← 5 Year Amortization →			← 5 Year Amortization →			17.34%
1960 Miscellaneous Equipment	← 5 Year Amortization →			← 5 Year Amortization →			20.00%
Total Amortizable			16.00%	3.95		36.06%	15.91%
Total General Plant			3.30%	29.52		20.50%	2.67%
TOTAL HYDRO ONE REMOTE COMMUNITIES			5.77%	12.01		44.31%	4.33%

HYDRO ONE REMOTE COMMUNITIES

Statement B

Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Plant Investment	2011 Annualized Accrual Current	2011 Annualized Accrual Proposed	2011 Annualized Accrual Difference
A	B	C	D	E=D-C
GENERATION PLANT				
1620 Buildings and Fixtures	$ 4,497,937	$ 81,413	$ 125,043	$ 43,630
1665 Fuel Holders, Producers and Accessories	5,372,646	123,571	148,822	25,251
1670 Prime Movers	13,703,994	1,766,445	922,279	(844,166)
1675 Generators	5,355,631	139,782	291,882	152,100
1680 Accessory Electric Equipment	1,361,324	31,583	74,056	42,473
1685 Miscellaneous Power Plant Equipment	2,244,654	52,525	87,317	34,792
Total Generation Plant	$ 32,536,186	$ 2,195,319	$ 1,649,399	$ (545,920)
DISTRIBUTION PLANT				
1805D Land - Depreciable	$ 294,456	$ 3,946	$ 5,712	$ 1,766
1806 Land Rights	234,126	3,184	2,271	(913)
1830 Poles, Towers and Fixtures	1,786,753	45,205	31,804	(13,401)
1835 Overhead Conductors and Devices	1,473,430	37,278	28,585	(8,693)
1845 Underground Conductors and Devices	186,177	9,421	5,641	(3,780)
1850 Line Transformers	1,738,469	50,242	41,897	(8,345)
1860 Meters	265,884	53,177	17,495	(35,682)
Total Distribution Plant	$ 5,979,295	$ 202,453	$ 133,405	$ (69,048)
GENERAL PLANT				
Depreciable				
1908 Buildings and Fixtures	$ 6,664,558	$ 171,946	$ 130,625	$ (41,321)
1955 Communication Equipment	20,332	3,208	687	(2,521)
Total Depreciable	$ 6,664,558	$ 171,946	$ 130,625	$ (41,321)
Amortizable				
1915 Office Furniture and Equipment	$ 39,115	$ 5,588	$ 5,588	$ -
1920 Computer Hardware - Minor	41,096	8,219	7,913	(306)
1935 Stores Equipment	148,458	18,358	18,358	
1940 Tools, Shop and Garage Equipment	6,078	1,013	1,013	
1945 Measurement and Testing Equipment	19,089	3,309	3,309	
1960 Miscellaneous Equipment	102,856	20,571	20,571	
Total Amortizable	$ 356,692	$ 57,058	$ 56,752	$ (306)
Total General Plant	$ 7,041,582	$ 232,212	$ 188,064	$ (44,148)
TOTAL HYDRO ONE REMOTE COMMUNITIES	$ 45,557,063	$ 2,629,984	$ 1,970,868	$ (659,116)

HYDRO ONE REMOTE COMMUNITIES

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
GENERATION PLANT							
1620 Buildings and Fixtures	$ 4,497,937	$ 812,304	18.06%	$ 1,148,684	25.54%	$ 1,257,845	27.96%
1665 Fuel Holders, Producers and Accessories	5,372,646	1,348,331	25.10%	1,328,554	24.73%	1,454,808	27.08%
1670 Prime Movers	13,703,994	12,353,668	90.15%	9,162,620	66.86%	10,033,360	73.21%
1675 Generators	5,355,631	1,637,429	30.57%	3,043,200	56.82%	3,332,400	62.22%
1680 Accessory Electric Equpment	1,361,324	278,787	20.48%	600,231	44.09%	657,272	48.28%
1685 Miscellaneous Power Plant Equipment	2,244,654	413,762	18.43%	475,106	21.17%	520,257	23.18%
Total Generation Plant	$ 32,536,186	$ 16,844,280	51.77%	$ 15,758,395	48.43%	$ 17,255,943	53.04%
DISTRIBUTION PLANT							
1805D Land - Depreciable	$ 294,456	$ 48,021	16.31%	$ 74,910	25.44%	$ 82,028	27.86%
1806 Land Rights	234,126	62,601	26.74%	49,564	21.17%	54,275	23.18%
1830 Poles, Towers and Fixtures	1,786,753	369,664	20.69%	322,260	18.04%	352,885	19.75%
1835 Overhead Conductors and Devices	1,473,430	391,383	26.56%	346,776	23.54%	379,731	25.77%
1845 Underground Conductors and Devices	186,177	102,438	55.02%	88,982	47.79%	97,438	52.34%
1850 Line Transformers	1,738,469	491,226	28.26%	444,564	25.57%	486,811	28.00%
1860 Meters	265,884	75,924	28.56%	32,615	12.27%	35,715	13.43%
Total Distribution Plant	$ 5,979,295	$ 1,541,258	25.78%	$ 1,359,671	22.74%	$ 1,488,883	24.90%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	$ 6,664,558	$ 1,362,978	20.45%	$ 1,182,766	17.75%	$ 1,295,166	19.43%
1955 Communication Equipment	20,332	24,321	119.62%	17,940	88.24%	19,645	96.62%
Total Depreciable	$ 6,684,890	$ 1,387,299	20.75%	$ 1,200,706	17.96%	$ 1,314,811	19.67%
Amortizable							
1915 Office Furniture and Equipment	$ 39,115	$ 10,193	26.06%	$ 10,193	26.06%	$ 10,193	26.06%
1920 Computer Hardware - Minor	41,096	17,225	41.92%	15,111	36.77%	15,111	36.77%
1935 Stores Equipment	148,458	6,768	4.56%	71,098	47.89%	71,098	47.89%
1940 Tools, Shop and Garage Equipment	6,078	1,435	23.61%	1,519	24.99%	1,519	24.99%
1945 Measurement and Testing Equipment	19,089	7,034	36.85%	7,035	36.85%	7,035	36.85%
1960 Miscellaneous Equipment	102,856	369,662	359.40%	23,661	23.00%	23,661	23.00%
Total Amortizable	$ 356,692	$ 412,318	115.59%	$ 128,617	36.06%	$ 128,617	36.06%
Total General Plant	$ 7,041,582	$ 1,799,616	25.56%	$ 1,329,323	18.88%	$ 1,443,428	20.50%
TOTAL HYDRO ONE REMOTE COMMUNITIES	$ 45,557,063	$ 20,185,154	44.31%	$ 18,447,389	40.49%	$ 20,188,253	44.31%

HYDRO ONE REMOTE COMMUNITIES
Current and Proposed Parameters
Vintage Group Procedure

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
GENERATION PLANT												
1620 Buildings and Fixtures	50.00	SQ	50.00	42.57			35.00	S6	34.85	25.95		
1665 Fuel Holders, Producers and Accessories	40.00	SQ	39.98	34.87			35.00	S6	34.94	26.30		
1670 Prime Movers	5.00	SQ	4.98	3.02			10.00	S6	12.01	3.98		
1675 Generators	33.00	SQ	32.88	26.15			16.00	S6	16.05	6.93		
1680 Accessory Electric Equipment	39.00	SQ	38.98	33.30			17.00	S6	17.01	9.51		
1685 Miscellaneous Power Plant Equipment	35.00	SQ	35.00	26.31			25.00	S6	25.04	19.74		
Total Generation Plant									16.88	8.71		
DISTRIBUTION PLANT												
1805D Land - Depreciable	75.00	SQ	75.00	67.28			50.00	S6	50.00	37.28		
1806 Land Rights	75.00	SQ	75.00	58.57			100.00	S6	100.00	78.83		
1830 Poles, Towers and Fixtures	40.00	L1.5	40.13	32.67			55.00	S2	54.89	44.99		
1835 Overhead Conductors and Devices	40.00	R2	40.20	32.36			50.00	S2	50.01	38.24		
1845 Underground Conductors and Devices	20.00	L1.5	20.57	12.69			30.00	S3	30.15	15.74		
1850 Line Transformers	35.00	S0.5	35.23	27.26			40.00	R2	40.20	29.92		
1860 Meters	5.00	SQ	5.00	1.17			15.00	R5	15.00	13.16		
Total Distribution Plant									43.52	33.62		
GENERAL PLANT												
Depreciable												
1908 Buildings and Fixtures	40.00	SQ	39.99	30.50	-4.2	-5.0	50.00	S4	49.98	41.11		
1955 Communication Equipment	7.00	SQ	7.00	3.50	-4.2	-5.0	7.00	S6	8.50	1.00		
Total Depreciable									49.98	41.11		
Amortizable												
1915 Office Furniture and Equipment	7.00	SQ	7.00	1.98			7.00	SQ	7.00	5.18		
1920 Computer Hardware - Minor	5.00	SQ	5.00	1.97			5.00	SQ	5.00	3.16		
1935 Stores Equipment	8.00	SQ	8.00	2.70			8.00	SQ	8.00	4.17		
1940 Tools, Shop and Garage Equipment	6.00	SQ	6.00				6.00	SQ	6.00	4.50		
1945 Measurement and Testing Equipment	5.00	SQ	5.00	3.39			5.00	SQ	5.00	3.16		
1960 Miscellaneous Equipment	5.00	SQ	5.00	2.29			5.00	SQ	5.00	3.85		
Total Amortizable									6.17	3.95		
Total General Plant									36.39	29.52		
TOTAL HYDRO ONE REMOTE COMMUNITIES									20.17	12.01		

HYDRO ONE REMOTE COMMUNITIES Statement E

Asset Category Summary
December 31, 2010
Harmonic Weighting

Description	P-Life		Proposed P-Life		Plant		Depreciation Reserve	
	USoA	IFRS	USoA	IFRS	USoA	IFRS	USoA	IFRS
A	B	C	D	E	F	G	H	I
1620 Buildings and Fixtures								
GENX-FSL -YD FACILITIES		35		35		134,244		27,070
GENX-FSL -LANDSCAPING		35		35		4,014		911
GENX-FSL REM- BLDG&STR		35		35		4,201,228		801,444
GENX-FSL -OTHER SITE IMPR		50		50		158,451		48,357
Total 1620	50-SQ	34	35-S6	35	4,497,937	4,497,937	812,304	877,781
1665 Fuel Holders, Producers and Accessories								
GENX -FSL REM-FUEL HANDLNG		35		35		5,372,646		1,261,256
Total 1665	40-SQ	35	35-S6	35	5,372,646	5,372,646	1,348,331	1,261,256
1670 Prime Movers								
GENX -FSL REM- DIESEL ENG		10		10		13,703,994		12,760,425
Total 1670	5-SQ	10	10-S6	10	13,703,994	13,703,994	12,353,668	12,760,425
1675 Generators								
GENX- HYD REM - TURBINES		50		50		659,034		153,061
GENX-FSL -AC STNDBY PWR		15		15		15,589		4,473
GENX-FSL REM ALT & AUX GEN		15		15		4,681,007		1,480,410
Total 1675	33-SQ	19	16-S6	18	5,355,631	5,355,631	1,637,429	1,637,943
1680 Accessory Electric Equipment								
GENX-FSL REM-WND&SOL GEN		20		20		41,445		9,515
GENX -FSL REM-STN TRANSF		20		20		549,409		166,836
GENX - FSL -ELE AUX SYST/CAB		15		15		770,470		108,799
Total 1680	39-SQ	17	17-S6	18	1,361,324	1,361,324	278,787	285,150
1685 Miscellaneous Power Plant Equipment								
GENX-FSL -INSTR&CNTRL EQU		15		15		652,896		168,674
GENX-FSL REM FIRE PROT SYS		35		35		624,060		145,935
GENX-FSL -COMMON SERV SYS		35		35		967,698		52,852
Total 1685	35-SQ	29	25-S6	26	2,244,654	2,244,654	413,762	367,461
1805 Land - Depreciable								
RURAL LANDS < 1975		50		50		294,456		48,781
Total 1805	75-SQ	50	50-S6	50	294,456	294,456	48,021	48,781
1806 Land Rights								
RURAL INTL CLRING & OVRBLDG		100		100		234,126		64,552
Total 1806	75-SQ	100	100-S6	100	234,126	234,126	62,601	64,552
1830 Poles, Towers, and Fixtures								
RURALSUPPORTS-WOOD,CONCRET		65		55		1,781,559		380,940
STEEL POLES SUPPORT		75		75		4,509		857
RURAL1995 YE ADJ STRM DAMAG		75		55		685		24
Total 1830	40-L1.5	65	55-S2	55	1,786,753	1,786,753	369,664	381,822
1835 Overhead Conductors and Devices								
RURAL SWITCHES/LOAD INTERPTR		50		40		90,308		20,951
RURAL OIL SECTNLZER&RECLSR SW		50		40		72,058		15,601
RURAL INSTALSECTNLZR&RCLSR SW		50		45		1,681		278
RURAL CONDUCTOR PRIM&SEC OVERH		75		50		1,304,105		339,098
RURAL VOLTAGE REGULATORS		50		40		5,278		1,524
Total 1835	40-R2	72	50-S2	49	1,473,430	1,473,430	391,383	377,451
1845 Underground Conductors and Devices								
RURAL CONDCTR SUBMARINE CBL		40		30		104,065		52,922
RURAL U/GRD CONDUCTOR-PRIME		50		30		59,349		28,701
RURAL U/GRD CONDR SEC SERV		50		30		19,929		12,013
RURAL U/GRD FUSE HOUSING		50		30		2,834		1,574
Total 1845	20-L1.5	44	30-S3	30	186,177	186,177	102,438	95,210

HYDRO ONE REMOTE COMMUNITIES Statement E

Asset Category Summary
December 31, 2010
Harmonic Weighting

Description	P-Life USoA	P-Life IFRS	Proposed P-Life USoA	Proposed P-Life IFRS	Plant USoA	Plant IFRS	Depreciation Reserve USoA	Depreciation Reserve IFRS
A	B	C	D	E	F	G	H	I
1850 Line Transformers								
RURAL OH TRFRMRS <=25 KVA		45		40		649,083		227,260
RURAL OH TRFMRS >25&<=50 KVA		45		40		175,487		33,117
RURAL OH TRFMRS>50&<=75 KVA		45		40		88,178		10,763
RURAL OH TRFMR >75&<=100 KVA		45		40		15,051		1,672
POLE TOP TRFS >200&<=300 KVA		45		40		45,575		15,908
POLE TOP TRFS >300&<=500 KVA		45		40		16,935		6,980
RURAL TRSF INSTAL		45		40		616,738		146,088
RURAL-U/GRD TRSF 0-50KVA		45		40		25,832		10,116
RURAL-U/GRD TRSF 301-500KVA		45		40		73		14
RURAL U/GRND TRFRMRS INSTAL		45		40		105,518		24,454
Total 1850	35-S0.5	45	40-R2	40	1,738,469	1,738,469	491,226	476,372
1908 Buildings and Fixtures								
GENRL-ADM&SERV-LANDSCAPING		50		50		55,635		4,287
GENRL-ADM&SERV_BLD FRAME&MTL		50		50		4,580,885		1,011,169
GENRL-ADM & SERV-BLD FRAME		50		50		1,734,577		244,651
GENRL -ADM & SERV-FENCE,GATE		50		30		133,057		10,885
GENRL- ADM & SERV-DISTN SYS		50		50		1,384		289
GENRL -ADM & SERV_AUX EQ BLD		50		50		159,020		32,448
Total 1908	40-SQ	50	50-S4	50	6,664,558	6,664,558	1,362,978	1,303,728
1955 Communication Equipment								
GENRL-ADM & SERV -TELCM WIRE		7		7		20,332		20,332
Total 1955	7-SQ	7	7-S6	7	20,332	20,332	24,321	20,332
TOTAL INVESTMENT					44,934,487	44,934,488	19,696,912	19,958,266
Reconciling Accounts								
Deer Lake					3,919,707	3,919,707	3,827,832	3,827,832
1860 - Meters (Depreciable)	5-SQ	5	15-R5	5	265,884	265,884	75,924	97,069
1915 - Office Furniture and Equiipment	7-SQ	7	7-SQ	7	39,115	39,115	10,193	10,193
1920 - Computer Hardware - Minor	5-SQ	5	5-SQ	5	41,096	41,096	17,225	16,135
1935 - Stores Equipment	8-SQ	8	8-SQ	8	148,458	148,458	6,768	71,097
1940 - Tools, Shop and Garage Equipment	6-SQ	6	6-SQ	6	6,078	6,078	1,435	1,435
1945 - Measurement and Testing Equipment	5-SQ	5	5-SQ	5	19,089	19,089	7,034	7,034
1960 - Miscellaneous Equipment	5-SQ	5	5-SQ	5	102,856	102,856	369,662	23,924
Total Reconciling Accounts					4,542,283	4,542,283	4,316,073	4,054,719
TOTAL HYDRO ONE REMOTE COMMUNITIES					49,476,770	49,476,771	24,012,985	24,012,985

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Remote Communities depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 1850 – Line Transformers. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the Hydro One Remote Communities review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis; and

Schedule E – Graphics Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

Schedule D – Actuarial Life Analysis

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

Schedule E – Graphics Analysis

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant
Account: 1850 Line Transformers

Dispersion: 40 - R2
Procedure: Vintage Group

Generation Arrangement

	December 31, 2010							
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2010	0.5	71,282	40.00	39.55	0.9887	1.0000	70,475	1,782
2009	1.5	56,835	40.00	38.65	0.9661	1.0000	54,908	1,421
2008	2.5	33,600	40.01	37.75	0.9436	1.0000	31,707	840
2007	3.5	68,843	40.02	36.87	0.9213	1.0000	63,423	1,720
2006	4.5	104,194	40.03	35.98	0.8990	1.0000	93,672	2,603
2005	5.5	100,848	40.04	35.11	0.8769	1.0000	88,431	2,519
2004	6.5	74,500	40.06	34.25	0.8549	1.0000	63,686	1,860
2003	7.5	48,337	40.08	33.39	0.8330	1.0000	40,263	1,206
2002	8.5	99,663	40.06	32.54	0.8121	1.0000	80,941	2,488
2001	9.5	184,839	39.96	31.69	0.7932	1.0000	146,610	4,626
2000	10.5	139,423	39.74	30.86	0.7765	1.0000	108,267	3,509
1999	11.5	20,446	39.54	30.03	0.7596	1.0000	15,531	517
1998	12.5	10,022	40.23	29.21	0.7263	1.0000	7,278	249
1997	13.5	3,395	40.32	28.41	0.7046	1.0000	2,392	84
1996	14.5	28,840	40.37	27.61	0.6838	1.0000	19,719	714
1994	16.5	73,286	40.10	26.04	0.6493	1.0000	47,588	1,828
1993	17.5	93,930	39.38	25.26	0.6415	1.0000	60,255	2,385
1992	18.5	121,740	40.56	24.50	0.6041	1.0000	73,542	3,001
1991	19.5	139,060	40.77	23.75	0.5826	1.0000	81,022	3,411
1990	20.5	187,014	40.76	23.01	0.5646	1.0000	105,593	4,588
1989	21.5	22,234	40.98	22.28	0.5438	1.0000	12,091	543
1988	22.5	8,240	40.87	21.57	0.5277	1.0000	4,348	202
1987	23.5	8,003	41.25	20.86	0.5056	1.0000	4,047	194
1986	24.5	11,989	41.39	20.16	0.4872	1.0000	5,840	290
1985	25.5	4,767	41.61	19.48	0.4682	1.0000	2,232	115
1984	26.5	15,064	41.62	18.81	0.4519	1.0000	6,807	362
1983	27.5	1,654	41.61	18.15	0.4362	1.0000	721	40
1982	28.5	2,313	41.69	17.50	0.4199	1.0000	971	55
1981	29.5	2,447	42.02	16.87	0.4015	1.0000	982	58
1978	32.5	254	43.20	15.05	0.3484	1.0000	89	6
1976	34.5	1,026	43.20	13.91	0.3220	1.0000	330	24
1960	50.5	380	50.98	6.85	0.1344	1.0000	51	7
Total	11.9	$1,738,469	40.20	29.92	0.7442	1.0000	$1,293,815	$43,246

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	2000 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2010	0.5	71,282		71,282	1.0000	0.5000
2009	1.5	56,835		56,835	1.0000	1.5000
2008	2.5	33,600		33,600	1.0000	2.5000
2007	3.5	68,843		68,843	1.0000	3.5000
2006	4.5	104,194		104,194	1.0000	4.5000
2005	5.5	100,848		100,848	1.0000	5.5000
2004	6.5	74,500		74,500	1.0000	6.5000
2003	7.5	48,337		48,337	1.0000	7.5000
2002	8.5	102,541		99,663	0.9719	8.4533
2001	9.5	204,532		184,839	0.9037	9.3180
2000	10.5	148,818		139,423	0.9369	10.0634
1999	11.5		22,481	20,446	0.9095	10.8212
1998	12.5		10,823	10,022	0.9259	12.4630
1997	13.5		3,395	3,395	1.0000	13.5000
1996	14.5		28,840	28,840	1.0000	14.5000
1994	16.5		86,626	73,286	0.8460	16.0801
1993	17.5		118,948	93,930	0.7897	16.2876
1992	18.5		125,660	121,740	0.9688	18.3762
1991	19.5		142,602	139,060	0.9752	19.4820
1990	20.5		190,479	187,014	0.9818	20.3636
1989	21.5		23,950	22,234	0.9284	21.4642
1988	22.5		11,076	8,240	0.7440	22.2270
1987	23.5		8,525	8,003	0.9389	23.4694
1986	24.5		13,282	11,989	0.9026	24.4513
1985	25.5		4,767	4,767	1.0000	25.5000
1984	26.5		15,506	15,064	0.9715	26.3353
1983	27.5		1,989	1,654	0.8316	27.1301
1982	28.5		2,737	2,313	0.8450	27.9948
1981	29.5		2,605	2,447	0.9394	29.1061
1978	32.5		254	254	1.0000	32.5000
1976	34.5		1,201	1,026	0.8546	33.8818
1965	45.5		98		0.0000	45.0000
1960	50.5		475	380	0.8000	49.2000
Total	11.9	$1,014,330	$816,318	$1,738,469	0.9496	

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	1,232,846	65,078	605	36,323	1,333,642
2001	1,333,642	357,340		236,083	1,927,064
2002	1,927,064	318,238	24,463	(462,889)	1,757,950
2003	1,757,950	107,020	15,862	(520,273)	1,328,835
2004	1,328,835	79,024	39,261	22,725	1,391,323
2005	1,391,323	71,972	3,219	52,460	1,512,536
2006	1,512,536	35,361	1,047	46,530	1,593,380
2007	1,593,380	101,146	1,822	(53,077)	1,639,628
2008	1,639,628	55,770	9,453	(27,386)	1,658,559
2009	1,658,559	47,549	8,613	(20,939)	1,676,556
2010	1,676,556	93,226	31,313		1,738,469

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	1,186,767	101,098		(20,505)	1,267,360
2001	1,267,360	277,366			1,544,726
2002	1,544,726	109,159	17,081	(305,161)	1,331,642
2003	1,331,642	48,337	5,447	(10,657)	1,363,875
2004	1,363,875	74,500	14,183	(25,078)	1,399,113
2005	1,399,113	108,101	3,219		1,503,995
2006	1,503,995	104,194	1,047	39,479	1,646,621
2007	1,646,621	68,843	1,822	(87,511)	1,626,131
2008	1,626,131	33,600	9,453		1,650,278
2009	1,650,278	56,835	8,613		1,698,500
2010	1,698,500	71,282	31,313		1,738,469

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

Placement Band: 1960-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	66.5	123.5	SC	3.03	173.0	R2 *	3.75	45.5	R3 *	4.09
2001-2005	64.9	92.5	O2	3.34	174.5	R2 *	5.86	44.9	R3 *	4.44
2002-2006	64.9	108.9	SC	3.16	177.2	R2.5 *	7.41	45.0	R4 *	4.33
2003-2007	66.4	71.5	L1	3.15	183.3	R4 *	8.64	48.2	R4 *	4.39
2004-2008	68.7	118.8	SC	4.33	184.1	R4 *	8.28	47.2	R4 *	3.61
2005-2009	91.4	184.3	R4 *	0.85	186.9	R4 *	1.45	51.5	R4 *	4.59
2006-2010	0.0	57.2	L0.5	19.39	138.5	SC *	23.10	41.6	R2 *	14.25

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2010	45.4	64.3	L0.5	6.51	74.8	O2	7.15	42.6	R2	4.54
2002-2010	44.0	61.4	L0.5	5.97	152.5	SC *	11.67	41.1	R2	5.34
2004-2010	43.8	56.5	L0.5	5.49	157.8	R0.5 *	13.38	41.0	R2.5 *	6.11
2006-2010	0.0	57.2	L0.5	19.39	138.5	SC *	23.10	41.6	R2 *	14.25
2008-2010	0.0	49.0	L0.5	16.26	145.4	SC *	24.36	38.4	R1.5 *	12.22
2010-2010	0.0	30.6	L1.5 *	8.80	56.7	O4 *	10.67	31.0	L1 *	9.01

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	100.0				No Retirements					
2000-2003	84.2	183.0	R4 *	4.81	101.2	R2.5	4.48	56.4	R3 *	4.35
2000-2005	66.2	104.2	SC	3.05	174.8	R2 *	5.09	46.8	R3	3.66
2000-2007	67.0	125.6	SC	4.55	182.6	R4 *	8.06	50.8	R4	4.29
2000-2009	73.7	176.5	R2.5 *	4.90	183.5	R4 *	6.52	49.7	R4 *	2.78
2000-2010	45.4	64.3	L0.5	6.51	74.8	O2	7.15	42.6	R2	4.54

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

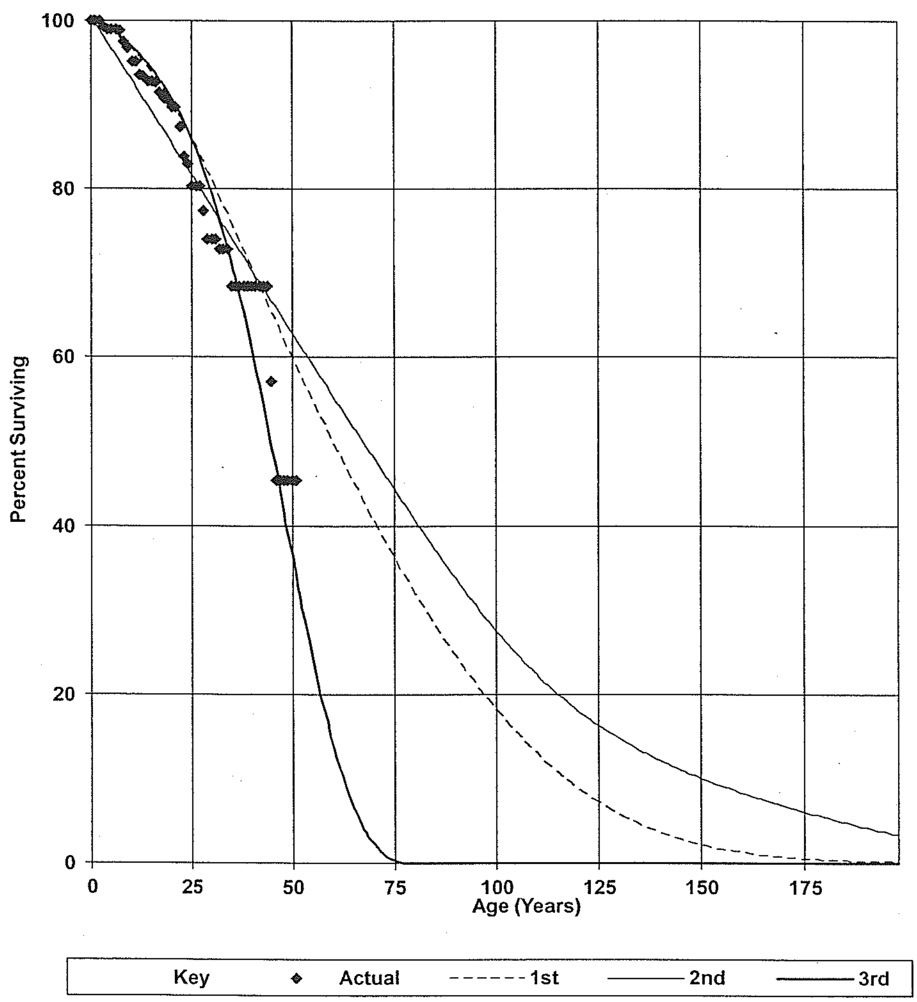
Placement Band: 1960-2010 Observation Band: 2000-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 64.3-L0.5 2nd: 74.8-O2 3rd: 42.6-R2



HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

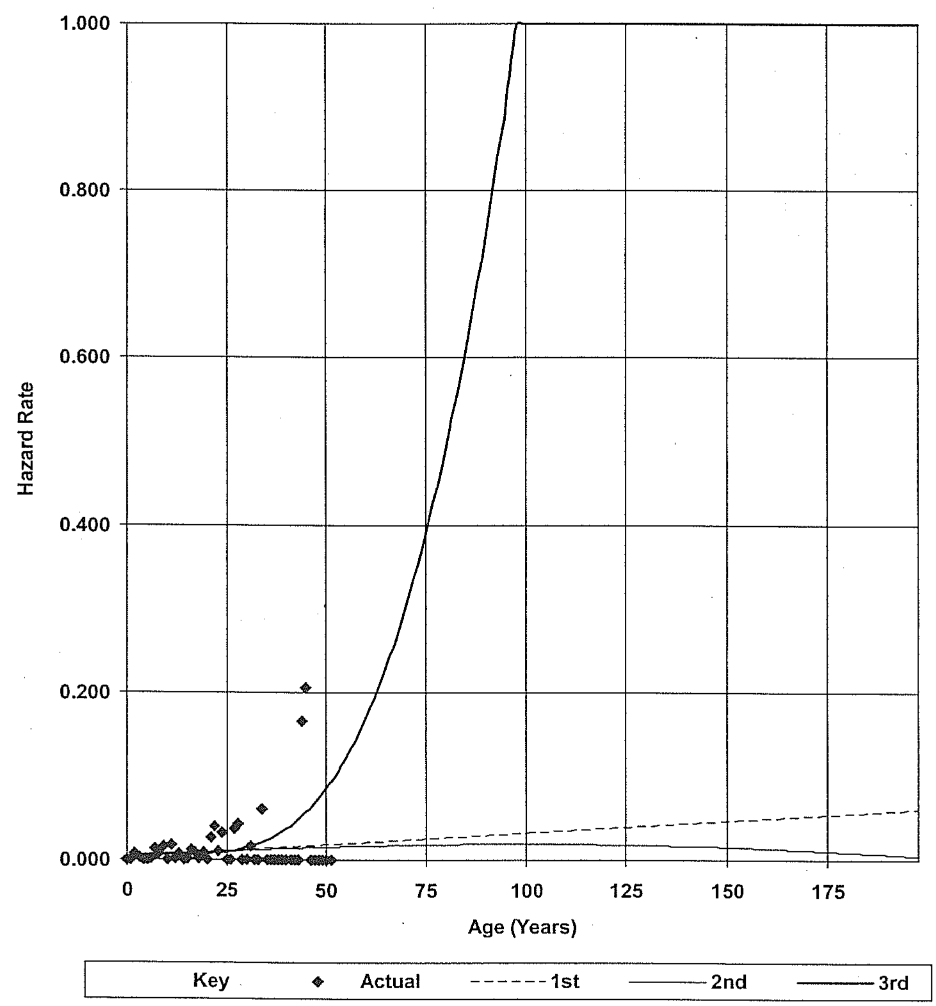
Placement Band: 1960-2010 Observation Band: 2000-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 64.3-L0.5 2nd: 74.8-O2 3rd: 42.6-R2



HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

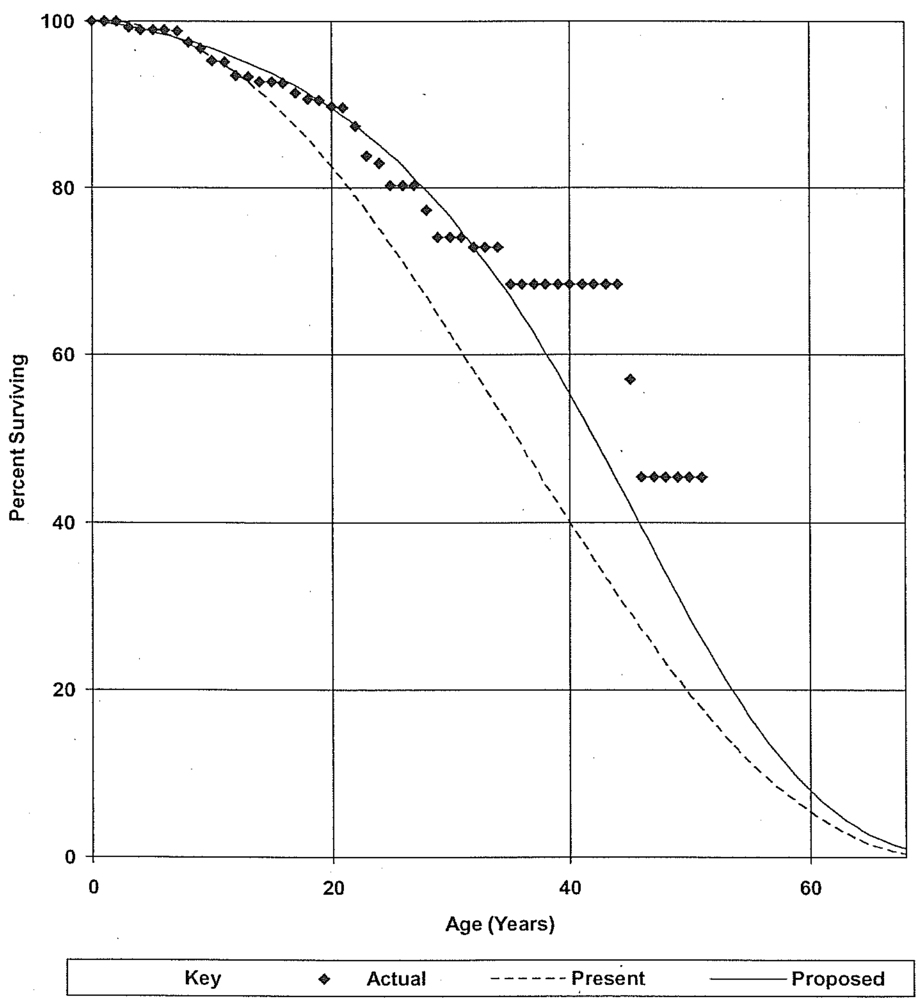
Account: 1850 Line Transformers

T-Cut: None

Placement Band: 1960-2010

Observation Band: 2000-2010

Present and Proposed Projection Life Curves Present: 35.0-S0.5 Proposed: 40.0-R2



PROFESSIONAL QUALIFICATIONS

NAME AND ADDRESS

Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 212
Fort Myers, FL 33908

EDUCATION

1961 - 1964 Valparaiso University

Major: Electrical Engineering

1965 Iowa State University

B.S., Engineering Operations

1968 Iowa State University

M.S., Engineering Valuation

Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University

Ph.D., Engineering Valuation

Minor: Economics

Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

EMPLOYMENT

2007 - Present	Foster Associates, Inc. Chairman
1996 - 2007	Foster Associates, Inc. Executive Vice President
1988 - 1996	Foster Associates, Inc. Senior Vice President
1979 - 1988	Foster Associates, Inc. Vice President
1978 - 1979	Northern States Power Company Assistant Treasurer
1974 - 1978	Northern States Power Company Manager, Corporate Economics
1972 - 1974	Northern States Power Company Corporate Economist

1970 - 1972	Iowa State University Graduate Student and Instructor
1968 - 1970	Northern States Power Company Valuation Engineer
1965 - 1968	Iowa State University Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of remaining-life technique and proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

SPEAKER

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.Page 48

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

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 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.

PILS installments are remitted by Remotes to the OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by the end of February of the following year.

The 2013 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 26.5% has been used for 2013 (Federal 15% and Ontario 11.5%). In 2012, a combined rate of 26.50% was also in effect, whereas, a combined rate of 28.25%, 31% and 33% was in effect in 2011, 2010 and 2009 respectively.

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 2013 is provided in Exhibit C2, Tab 5, Schedule 1, Attachment 1. This schedule reflects adjustments to regulatory NIBT to arrive at taxable income. 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 5, Schedule 1, Attachment 3.

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 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 US generally accepted accounting principles (US GAAP) 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. This includes items such as depreciation, contingent liabilities, accounting provisions such as other post employment benefits ("OPEB") etc. On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, environmental and OPEB payments.

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 and capitalized interest). That is, for test year 2013, 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 Board.

For example, as shown in Table 1, assuming that a 25% tax rate and a $100 expense is incurred, 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 Board subsequently approves recovery of this expense over a two 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 or expense has been taxed or deducted in different years.

Table 1

	Year 1	**Year 2**	**Year 3**	**CUM**
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	25	(12.5)	(12.5)	Nil
Cash Inflow (outflow)	(75)	37.5	37.5	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 or 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.

It is not necessary to adjust the 2013 NIBT for contingent liabilities in computing taxable income since no changes were forecasted in the contingent liability balance for 2013. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

7.0 ONTARIO CAPITAL TAX

As of July 1, 2010, the Ontario capital tax was eliminated. Therefore there is no Ontario capital tax calculated for the 2013 test year.

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 weekly time-entry. 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 thirteen of the communities Remotes served are not accessible by year-round road, staff, equipment and cargo are transported to the communities by aircraft. Remotes contracts out the 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. This cost is implicit in the labour rate ("fully loaded") and is $6 per hour in the test year.

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) along with assigned Remote administrative costs. Those total payable 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 2013 Forecasted Labour Rate	**Billable $ per Hr.**
Composition Of Standard Labour Rate	$**184**
Includes the following components:	
Meal Surcharge	$6
Payroll Obligations	$76
Non-Labour Administration Costs	$21
Non-Project, Administration, Management and Support Services Labour	$81

2.1.1 Payroll Obligations ($76)

A brief description of the cost elements included in this category is provided below.

Labour and Payroll Allowances (68% 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.

<u>Company Benefits (25% of Payroll Obligations)</u>

- Regular Staff: Comprised of Pension (28.9% of base pensionable earnings) and current and post employment benefits; health, dental, etc. (24.1 % of base pensionable earnings).

<u>Government Obligations (4% of Payroll Obligations)</u>

- Consists of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board Schedule 1 Premiums (WSIB);
- In 2013, 5.78 percent is to be applied against total earnings (includes base pay, bonus, overtime, benefits and taxable allowances) to recover these costs.

2.1.2 <u>Non Labour Administration Costs ($21)</u>

This category consists primarily of non-labour expenses incurred by the business necessary for the business operations. This includes 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 budgeted based on historical trends and consider current company initiatives and individual interdepartmental need.

2.1.3 <u>Non-Project, Administration and Support Services Labour ($81)</u>

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 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 Networks Inc. 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 incurs 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. Periodically, Remotes also incurs fuel and maintenance costs outside of those incurred by Hydro One Networks Inc. (and included in the SLA). 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.

2013 TWE Cost Forecast (including SLA)	$810,000
2013 Forecasted TWE Hours	17,400
2013 Total Average TWE Rate/Hour	$47

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 2013 forecasted SMS rate is 1.9%.

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 and is therefore recovered in the hourly charge out rate. The rate per hour is based on forecasted meal expense and planned labour hours.

HYDRO ONE REMOTE COMMUNITIES INC.

Cost of Service

Historical (2009, 2010, 2011), Bridge (2012) and Test (2013) Years
Year Ending December 31
($000s)

Line No.	Particulars	2009	2010	2011	2012	2013
		(a)	(b)	(c)	(e)	(f)
1	Total Operation, Maintenance & Administrative Expenses	30,126	35,326	37,803	40,033	44,199
2	Depreciation & Amortization Expenses	4,017	4,242	4,694	6,964	6,030
3	Capital Taxes	89	28	-	-	-
4	Income Taxes (Note1)	1,826	731	(164)	54	(187)
5	**Total Cost of Service**	**36,058**	**40,327**	**42,333**	**47,051**	**50,042**

Note 1: Historic years calculated per tax returns; Bridge year per tax return projection; test year based on revenue requirement

HYDRO ONE REMOTES
Mapping OM&A Expenditures to Grouped USofA Accounts for years 2011 - 2013
As at December 31
($000s)

Line No.	Minimum USofA Grouping	Account Numbers	2011	2012	2013
1	Generation - Operation	4510, 4550, 4555	26,600	27,310	28,640
2	Generation - Maintenance	4610, 4635	6,558	7,145	6,012
3	Generation - Other Power Supply	4705	0	0	1,980
4	Distribution Expenses - Operation	5085	112	294	301
5	Distribution Expenses- Maintenance	5120, 5125, 5130, 5135, 5175	1,232	1,608	3,279
6	Customer Care (Billing and Collecting)	5310, 5315, 5320, 5335	1,734	1,727	1,903
7	Community Relations	5410, 5415, 5420, 5425	444	846	866
8	Administrative and General Expenses	5615, 5625, 5655,6205	994	1,042	1,157
8	External Costs	4330	129	61	61
10	**Total OM&A**		**37,803**	**40,033**	**44,199**

COMPARISON OF WAGES AND SALARIES

Year	Representation	Total Pay	Base Pay	Overtime Amount Paid Including Premium	Incentive Pay	Other Allowances	Head Count
2009	MCP	704,933	596,073		75,700	33,160	5
	PWU	2,632,406	2,099,217	488,556		44,633	26
	SOCIETY	950,510	894,955	40,055		15,500	10
	Total	**4,287,849**	**3,590,245**	**528,611**	**75,700**	**93,293**	**41**
2010	MCP	672,986	607,197		42,590	23,199	5
	PWU	2,819,549	2,114,704	553,245		151,600	27
	SOCIETY	1,016,772	963,505	54,442		-1,175	11
	Total	**4,509,307**	**3,685,406**	**607,687**	**42,590**	**173,624**	**43**
2011	MCP	697,927	608,552		56,214	33,160	5
	PWU	3,083,450	2,245,386	692,736		145,327	27
	SOCIETY	1,322,061	1,224,100	87,308		10,652	12
	Total	**5,103,437**	**4,078,039**	**780,044**	**56,214**	**189,140**	**44**
2012	MCP	718,864	626,809		57,900	34,155	5
	PWU	3,518,583	2,655,377	713,518		149,687	31
	SOCIETY	1,361,722	1,260,823	89,928		10,971	12
	Total	**5,599,170**	**4,543,010**	**803,446**	**57,900**	**194,814**	**48**
2013	MCP	740,430	645,613		59,637	35,180	5
	PWU	3,624,140	2,735,039	734,924		154,178	31
	SOCIETY	1,402,574	1,298,648	92,625		11,301	12
	Total	**5,767,145**	**4,679,300**	**827,549**	**59,637**	**200,658**	**48**

HYDRO ONE REMOTE COMMUNITIES INC.

Depreciation & Amortization Expenses
Bridge Year (2012) and Test Year (2013)
Year Ending December 31
($000s)

Line No.	Particulars	2012 Provision	2013 Provision
		(b)	(d)
	Depreciation Expenses		
1	Major Fixed Assets	2,808	2,491
2	Minor Fixed Assets	90	105
3	Depreciation on Fixed Assets	2,898	2,596
5	Asset Removal Costs	592	721
6	Losses/(Gains)	-	-
7	Total Depreciation Expenses	3,490	3,317
	Amortization Expenses		
8	Environmental Costs	3,474	2,713
9	Total Amortization Expenses	3,474	2,713
10	Total Depreciation & Amortization I	6,964	6,030

HYDRO ONE REMOTE COMMUNITIES INC.

Depreciation & Amortization Expenses
Historical Years (2009, 2010 and 2011)
Year Ending December 31
($000s)

Line No.	Particulars	2009 Provision	2010 Provision	2011 Provision
		(b)	(b)	(b)
	Depreciation Expenses			
1	Major Fixed Assets	2,617	2,759	2,831
2	Minor Fixed Assets	40	56	78
3	Depreciation on Fixed Assets	2,657	2,815	2,909
5	Asset Removal Costs	377	271	768
6	Losses/(Gains) on Asset Dispositic	0	(112)	0
7	Total Depreciation Expenses	3,034	2,974	3,677
	Amortization Expenses			
8	Environmental Costs	983	1,268	1,017
9	Total Amortization Expenses	983	1,268	1,017
10	Total Depreciation & Amortization I	4,017	4,242	4,694

CALCULATION OF UTILITY INCOME TAXES

Attachment 1- Calculation of Utility Income Taxes: Test Year 2013

Attachment 2- Calculation of Capital Cost Allowance: Test and Bridge Years 2012 and 2013

Attachment 3- Calculation of Utility Income Taxes: Historic Years 2009-2011

Attachment 4- Calculation of Capital Cost Allowance: Historic Years 2009-2011

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Utility Income Taxes
Test Year (2013)
Year Ending December 31
($000s)

Line No.	Particulars		2013	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)	$	(187)	
2	Book to Tax Adjustments:			
3	Other Post Employment Benefits expense		552	
4	Other Post Employment Benefits payments		(374)	
5	Depreciation and amortization		6,030	
6	Capital Cost Allowance		(2,741)	
7	Removal costs		(296)	
8	Environmental costs		(2,713)	
9	Non-deductible meals & entertainment		150	
10	Capitalized interest deduction		(266)	
11	Capitalized overhead costs deduction		(456)	
12	Capitalized pension costs deduction		(407)	
13		$	(520)	
14				
15	Regulatory Taxable Income	$	(707)	
16				
17				
18	Calculation of Utility Income Taxes			
19				
20	Corporate Income Tax Rate		26.50	%
21				
22	Regulatory Income Tax	$	(187)	
23				
24				
25	Income Tax Rates:			
26				
27	Federal Tax		15.00	%
28	Provincial Tax		11.50	%
29	Total Federal and ON Tax rate		26.50	%

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Capital Cost allowance (CCA)
Test and Bridge Year
2012 & 2013
Year Ending December 31
($000s)

2013 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	16,722.5	398.9	17,121.5	199.5	16,922.0	4%	676.9	16,444.6
2	523.5	0.0	523.5	0.0	523.5	6%	31.4	492.1
3	855.1	109.8	964.9	54.9	910.0	5%	45.5	919.4
6	2,835.4	365.2	3,200.6	182.6	3,018.0	10%	301.8	2,898.8
8	770.3	299.4	1,069.7	149.7	920.0	20%	184.0	885.7
10	236.9	16.2	253.1	8.1	245.0	30%	73.5	179.6
12	0.2	3.7	3.8	1.8	2.0	100%	2.0	1.8
13	37.8	-	37.8	-	37.8	SL	4.7	33.0
17	10,782.4	1,309.2	12,091.6	654.6	11,437.0	8%	915.0	11,176.6
42	229.4	25.1	254.6	12.6	242.0	12%	29.0	225.5
43.1	0.6	-	0.6	-	0.6	30%	0.2	0.5
45	1.2	-	1.2	-	1.2	45%	0.5	0.7
47	4,791.0	2,166.0	6,957.0	1,083.0	5,874.0	8%	474.9	6,482.1
50	2.6	0.8	3.4	0.4	3.0	55%	1.7	1.7
CCA	**37,789.0**	**4,694.3**	**42,483.3**	**2,347.2**	**40,136.1**		**2,741.1**	**39,742.2**

2012 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	17,148.3	301.7	17,450.0	150.8	17,299.2	4%	727.5	16,722.5
2	556.9	-	556.9	-	556.9	6%	33.4	523.5
3	782.2	114.9	897.1	57.4	839.6	5%	42.0	855.1
6	2,727.5	400.7	3,128.2	200.3	2,927.9	10%	292.8	2,835.4
8	826.4	121.4	947.7	60.7	887.0	20%	177.4	770.3
10	256.3	67.6	323.9	33.8	290.1	30%	87.0	236.9
12	2.1	0.3	2.5	0.2	2.3	100%	2.3	0.2
13	42.5		42.5	-	42.5	SL	4.7	37.8
17	9,583.8	2,047.2	11,631.0	1,023.6	10,607.4	8%	848.6	10,782.4
42	218.0	40.0	258.0	20.0	238.0	12%	28.6	229.4
43.1	0.9	0.0	0.9	0.0	0.9	30%	0.3	0.6
45	2.2	-	2.2	-	2.2	45%	1.0	1.2
47	3,095.3	2,024.3	5,119.6	1,012.2	4,107.4	8%	328.6	4,791.0
50	2.3	2.2	4.5	1.1	3.4	55%	1.9	2.6
CCA	**35,244.8**	**5,120.2**	**40,365.0**	**2,560.1**	**37,804.9**		**2,576.0**	**37,789.0**

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Utility Income Taxes
Historic Years
2009-2011
Year Ending December 31
($000s)

Line No.	Particulars	2009	2010	2011
	Calculation of Federal and ON Taxable Income			
1	Net Income Before Tax (NIBT)	$ 2,824	$ 1,324	$ (127)
2	**Required Adjustments to accounting NIBT**			
3	**Recurring items included in Revenue Requirement (RR):**			
4	Post Employment Benefit accrual in excess of payments	197	256	303
5	Depreciation and amortization	4,018	4,243	4,694
6	Capital Cost Allowance	(2,169)	(2,199)	(2,318)
7	Removal costs	(135)	(170)	(309)
8	Environmental costs deduction	(983)	(1,268)	(1,017)
9	Non-deductible M & E / interest	159	251	104
10	Capitalized overhead costs deducted	(365)	(347)	(494)
11	Capitalized Pension costs deducted			(417)
12		$ 721	$ 766	$ 546
13	**Deferral accounts not part of RR:**			
14	RRRP	6,934	305	(834)
15		$ 6,934	$ 305	$ (834)
16	**Reversal of accounting adjustments not part of RR:**			
17	Capitalized interest deductible for tax	(156)	(126)	(166)
18		$ (156)	$ (126)	$ (166)
19	**Recurring items not part of RR:**			
20				
21	Immaterial items not in business plan detail:			
22	Capital items deducted for accounting	18	80	17
23	Interest deduction net of financing costs amortized	(10)	14	14
24	Capital tax provision overaccrual (under) vs. return	31	1	(32)
25	Other	(3)	(3)	2
26		35	91	1
27				
28	NET Adjustments to Accounting NIBT	$ 10,358	$ 1,036	$ (452)
29	Prior years Non capital loss C/F utilized	(4,823)	-	-
30	Taxable Income Federal and Ontario	$ 5,535	$ 2,360	$ (579)
31				
32	**Income Tax:**			
33	Federal Income Tax	1,052	425	(96)
34	ON Income Tax	775	307	(68)
35	Total Income Tax Per Returns	1,826	731	(164)
36				
37				
38	**ON Capital tax per Return**	89	28	-
39				
40	Federal Tax	19.00 %	18.00 %	16.50 %
41	Provincial Tax	14.00 %	13.00 %	11.75 %
42	Corporate Income Tax Rate	33.00 %	31.00 %	28.25 %

See Exhibit C1, Tab 5, Schedule 1 for additional information

HYDRO ONE REMOTE COMMUNITIES INC.

Calculation of Capital Cost allowance (CCA)
Historic Years
2009-2011
Year Ending December 31
($000s)

2011

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	16,252.4	1,577.6	17,830.0	788.8	17,041.2	4%	681.6	17,148.3
2	592.4	-	592.4	-	592.4	6%	35.5	556.9
3	823.3	-	823.3	-	823.3	5%	41.2	782.2
6	2,905.5	118.5	3,024.0	59.3	2,964.8	10%	296.5	2,727.5
8	815.7	193.1	1,008.8	96.5	912.3	20%	182.5	826.4
10	149.7	178.2	327.9	89.1	238.8	30%	71.6	256.3
12	0.3	4.3	4.5	2.1	2.4	100%	2.4	2.1
13	-	47.3	47.3	-	-	SL	4.7	42.5
17	7,773.8	2,533.3	10,307.0	1,266.6	9,040.4	8%	723.2	9,583.8
42	247.8	-	247.8	-	247.8	12%	29.7	218.0
43.1	1.3	-	1.3	-	1.3	30%	0.4	0.9
45	4.0	-	4.0	-	4.0	45%	1.8	2.2
47	2,771.6	568.1	3,339.7	284.1	3,055.7	8%	244.5	3,095.3
50	3.3	1.2	4.5	0.6	3.9	55%	2.1	2.3
52	-	-	-	-	-	100%	-	-
CCA	**32,341.1**	**5,221.5**	**37,562.6**	**2,587.1**	**34,928.2**		**2,317.8**	**35,244.8**

2010

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	15,392.9	1,505.3	16,898.2	752.6	16,145.6	4%	645.8	16,252.4
2	630.3	-	630.3	-	630.3	6%	37.8	592.4
3	866.7	-	866.7	-	866.7	5%	43.3	823.3
6	3,228.3	-	3,228.3	-	3,228.3	10%	322.8	2,905.5
8	779.2	213.7	993.0	106.9	886.1	20%	177.2	815.7
10	94.6	98.3	192.9	49.1	143.7	30%	43.1	149.7
12	1.8	0.5	2.3	0.3	2.1	100%	2.1	0.3
17	7,872.4	553.3	8,425.7	276.6	8,149.1	8%	651.9	7,773.8
42	281.5	-	281.5	-	281.5	12%	33.8	247.8
43.1	1.8	-	1.8	-	1.8	30%	0.5	1.3
45	7.4	-	7.4	-	7.4	45%	3.3	4.0
47	2,062.5	910.5	2,973.0	455.3	2,517.7	8%	201.4	2,771.6
50	7.3	-	7.3	-	7.3	55%	4.0	3.3
52	-	32.2	32.2	32.2	32.2	100%	32.2	-
CCA	**31,226.7**	**3,313.8**	**34,540.5**	**1,673.0**	**32,899.7**		**2,199.4**	**32,341.1**

2009

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	16,022.9	11.1	16,034.0	5.6	16,028.5	4%	641.1	15,392.9
2	670.5	-	670.5	-	670.5	6%	40.2	630.3
3	912.3	-	912.3	-	912.3	5%	45.6	866.7
6	2,798.6	747.0	3,545.5	373.5	3,172.0	10%	317.2	3,228.3
8	990.3	(16.3)	974.0	(16.3)	974.0	20%	194.8	779.2
10	135.1	-	135.1	-	135.1	30%	40.5	94.6
12	7.1	3.6	10.7	1.8	8.9	100%	8.9	1.8
17	6,361.0	2,104.5	8,465.5	1,052.2	7,413.3	8%	593.1	7,872.4
42	-	299.5	299.5	149.8	149.8	12%	18.0	281.5
43.1	2.6	-	2.6	-	2.6	30%	0.8	1.8
45	13.4	-	13.4	-	13.4	45%	6.0	7.4
47	923.6	1,263.3	2,186.9	631.7	1,555.2	8%	124.4	2,062.5
50	16.3	-	16.3	-	16.3	55%	9.0	7.3
52	-	129.3	129.3	129.3	129.3	100%	129.3	-
CCA	**28,853.6**	**4,542.0**	**33,395.6**	**2,327.5**	**31,181.1**		**2,168.9**	**31,226.7**

2011 HYDRO ONE REMOTE COMMUNITIES INC.

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 or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 87083 6269 RC0001

Corporation's name
002 Hydro One Remote Communities Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . 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 we were notified? . . . . 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 we were notified? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031
032
City: 035
Province,territory, or state: 036
Country (other than Canada): 037
Postal code/Zip code: 038

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 2011-01-01 (YYYY MM DD)
Tax year-end: 061 2011-12-31 (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 according to:
subparagraph 88(2)(a)(iv)? . . . . 064 1 Yes [ ] 2 No [X]
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]

If an election was made under section 261, state the functional currency used 079

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
095
096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	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	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	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	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	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 deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity generation and distribution	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
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		X

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ (YYYY MM DD)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	-576,988 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 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

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 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . 405 ______ B

Business limit (see notes 1 and 2 below) . . . . . 410 ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x 415 ***** 34,109,806 D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . 425 ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = ... 430 ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Personal service business income**	432	D	
Amount used to calculate the credit union deduction from Schedule 17		E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F	
Aggregate investment income from line 440 on page 6***		G	
Total of amounts B to G		►	H
Amount A **minus** amount H (if negative, enter "0")			I

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	/ 365	x	9 %	=	J
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	/ 365	x	10 %	=	K
Amount I	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	L
Amount I	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M .... N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		P	
Amount QQ from Part 13 of Schedule 27		Q	
Personal service business income*	434	R	
Amount used to calculate the credit union deduction from Schedule 17		S	
Total of amounts P to S		►	T
Amount O **minus** amount T (if negative, enter "0")			U

Amount U	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	V
Amount U	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	W
Amount U	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	X
Amount U	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	Y

General tax reduction – Total of amounts V to Y .... Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x 26 2/3 % = ... ______ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ______

Deduct:
Foreign investment income from Schedule 7 . . . . **445** ______ x 9 1/3 % = ______
(if negative, enter "0") ______ ▶ ______ B

Amount A **minus** amount B (if negative, enter "0") . . . . ______ C

Taxable income from line 360 on page 3 . . . . ______

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ______

Foreign non-business income tax credit from line 632 on page 7 . . . ______ x 25/9* 25 / 9 = ______

Foreign business income tax credit from line 636 on page 7 . . . . ______ x 1(0.38 - X**) 3.77358 = ______
______ ▶ ______
______ x 26 2/3 % = ______ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ______ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ______ F

* 100/35 for tax years beginning after October 31, 2011.
** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______
Deduct: Dividend refund for the previous tax year . . . . **465** ______
______ ▶ ______ G

Add the total of:
Refundable portion of Part I tax from line 450 above . . . . ______
Total Part IV tax payable from Schedule 3 . . . . ______
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______
______ ▶ ______ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ______ 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 on page 8) . . . . ______

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	550		A
Recapture of investment tax credit from Schedule 31	602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3			
Deduct: Amount from line 400, 405, 410, or 425 on page 4, 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		C
Subtotal (**add** lines A to C)			D

Deduct:

Small business deduction from line 430 on page 4			1
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		
General tax reduction for CCPCs from amount N on page 5	638		
General tax reduction from amount Z on page 5	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		▶	E

Part I tax payable – Line D **minus** line E		F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	
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 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	3,000
Tax instalments paid	840	14,835
Total credits	890	17,835 ▶ 17,835 B

Refund code 894 2   Overpayment 17,835

Balance (line A **minus** line B) -17,835

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 also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-09-05 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

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

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SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant 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 accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . . . 1 [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 with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [X] 2 No [ ]

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]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

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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	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				11,235 A
Add:				
Provision for income taxes – current		101	-127,000	
Interest and penalties on taxes		103	18,508	
Amortization of tangible assets		104	4,693,765	
Non-deductible meals and entertainment expenses		121	85,789	
Reserves from financial statements – balance at the end of the year		126	25,865,055	
Subtotal of additions			30,536,117 ▶	30,536,117
Other additions:				
Debt issue expense		208	14,290	
Miscellaneous other additions:				
604 Computer software expensed	17,179			
Coop Tax Credit	3,000			
Total	20,179	294	20,179	
Subtotal of other additions		199	34,469 ▶	34,469
Total additions		500	30,570,586 ▶	30,570,586
Deduct:				
Capital cost allowance from Schedule 8		403	2,316,360	
Reserves from financial statements – balance at the beginning of the year		414	19,837,132	
Subtotal of deductions			22,153,492 ▶	22,153,492
Other deductions:				
Non-taxable/deductible other comprehensive income items		347	11,235	
Miscellaneous other deductions:				
700 Reverse Environmental interest and accruals reflected on S13		390	7,304,737	
701 WSIB gain included in income		391	3,108	
703 Removal expense added back via depreciation	308,690			
Total	308,690	393	308,690	
704 Refer to supporting schedule	1,074,532			
OEB costs capitalized	271,074			
Capital tax recovery	31,941			
Total	1,377,547	394	1,377,547	
Subtotal of other deductions		499	9,005,317 ▶	9,005,317
Total deductions		510	31,158,809 ▶	31,158,809
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-576,988

T2 SCH 1 E (10)

Canada

Attached Schedule with Total

Line 208 – Debt issue expense

Title Line 208 – Debt issue expense

Description	Amount	
Amortization underwriting fee (761780)	2,027	00
Amortization of Hedge loss (761770)	11,716	00
Bond Discount (761120,761130)	547	00
Total	14,290	00

Attached Schedule with Total

Line 704 – Amount

Title Line 704 – Amount

Description	Amount	
Interest Improvement - Regulatory Assets	166,297	00
Capitalized overhead	494,497	00
Pension costs capitalized	413,738	00
Total	1,074,532	00

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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	2011-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation 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. Also, 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 the schedule by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				-576,988	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under sections 112, 113(1), or subsection 138(6)			b		
Amount of Part VI.1 tax deductible			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				-576,988	C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)				-576,988	E
Add: (decrease a loss)					
Current-year farm loss (whichever is less: the net loss from farming or fishing included in the income, or the non-capital loss before deducting the farm loss. Enter amount F on line 310)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0"; if negative, enter amount G on line 110 as a positive)				-576,988	G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired*	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102		▶		H
Add:					
Non-capital losses transferred on an amalgamation or the wind-up of a subsidiary corporation	105		g		
Current-year non-capital loss (amount G above)	110	576,988	h		
Subtotal (amount g **plus** amount h)		576,988	▶	576,988	I
Subtotal (amount H **plus** amount I)				576,988	J

* 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; and
- 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; and
- after **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

	Line	Amount			Total	
Amount J from page 1					576,988	
Deduct:						
Other adjustments (includes adjustments for an acquisition of control)	150		i			
Section 80 – Adjustments for forgiven amounts	140		j			
Subsection 111(10) – Adjustments for fuel tax rebate			j.1			
Non-capital losses of previous tax years applied in the current tax year (enter on line 331 of the T2 Return)	130		k			
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 330 and 335 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	135		l			
Subtotal (total of amounts i to l)				▶		K
Non-capital losses before any request for a carryback (amount J **minus** amount K)					576,988	L
Deduct – **Request to carry back non-capital loss to:**						
First previous tax year to reduce taxable income	901		m			
Second previous tax year to reduce taxable income	902	576,988	n			
Third previous tax year to reduce taxable income	903		o			
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r			
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		576,988		▶	576,988	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180					N

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

	Line	Amount			Total	
Capital losses at the end of the previous tax year	200		a			
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		b			
Subtotal (amount a **plus** amount b)				▶		A
Deduct:						
Other adjustments (includes adjustments for an acquisition of control)	250		c			
Section 80 – Adjustments for forgiven amounts	240		d			
Subtotal (amount c **plus** amount d)				▶		B
Subtotal (amount A **minus** amount B)						C
Add: Current-year capital loss (from the calculation on Schedule 6)	210					D
Unused non-capital losses that expired in the tax year*			e			
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			f			
Enter amount e or f, whichever is less	215					
ABILs expired as non-capital loss: line 215 **divided** by 0.500000	220					E
Subtotal (total of amounts C to E)						F

Note
If there has been an amalgamation or a windup 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 on line 220 above.

* If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th 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 11th previous tax year. 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 e.

** If the losses were incurred in a tax year ending before March 23, 2004, enter the losses from the 8th previous tax year. If the losses were incurred in a tax year ending after March 22, 2004, enter the losses from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

			Amount F from page 2		
Deduct: Capital losses from previous tax years applied against the current-year net capital gain (see Note 1)			225		G
			Capital losses before any request for a carryback (amount F **minus** amount G)		H

Deduct – **Request to carry back capital loss to** (see Note 2):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951		g	
Second previous tax year		952		h	
Third previous tax year		953		i	
	Subtotal (total of amounts g to i)				I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)				280	J

Note 1

To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the purpose of current-year tax, enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On line 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.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired*	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302				A
Add:					
Farm losses transferred on the amalgamation or the windup of a subsidiary corporation	305		c		
Current-year farm loss	310		d		
Subtotal (amount c **plus** amount d)					B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year (enter on line 334 of the T2 Return)	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (enter on lines 340 and 345 of Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*, respectively)	335		h		
Subtotal (total of amounts e to h)					D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)					F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)				380	G

* A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- 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			A
Minus the deductible farm loss:				
(amount A above ______ – $2,500) **divided** by 2 = ______				a
Amount a or $ 6,250, whichever is less				b
		2,500		c
Subtotal (amount b **plus** amount c)		2,500	2,500	B
Current-year restricted farm loss (amount A **minus** amount B; enter amount C on line 410)				C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year				d
Deduct: Restricted farm loss expired*	400			e
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402			D
Add:				
Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405			f
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410			g
Subtotal (amount f **plus** amount g)				E
Subtotal (amount D **plus** amount E)				F
Deduct:				
Restricted farm losses from previous tax years applied against current farming income (enter on line 333 of the T2 Return)	430			h
Section 80 – Adjustments for forgiven amounts	440			i
Other adjustments	450			j
Subtotal (total of amounts h to j)				G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)				H

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941			k
Second previous tax year to reduce farming income	942			l
Third previous tax year to reduce farming income	943			m
Subtotal (total of amounts k to m)				I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480			J

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; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuité des pertes sur des biens meubles déterminés et demande de report rétrospectif

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after seven tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)				510	B
Subtotal (amount A **plus** amount B)					C

Deduct:

Previous year personal property losses applied in the current tax year against listed personal property gains (enter on line 655 of Schedule 6)	530		c		
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E

Deduct – Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580	G

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Tax year ending YYYY/MM/DD	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 **minus** 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Tax year ending YYYY/MM/DD	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

1	2	3	4	5	6
Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the windup of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied in the current year (cannot be more than column 650)	Current year limited partnership losses closing balance to be carried forward to future years (662 + 664 + 670 – 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Note

If you have any current–or previous–year losses, enter your partnership identifier on line 600, 630, or 660.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

Further to a winding-up of a subsidiary, the portion of a non-capital loss, restricted farm loss, farm loss, or limited partnership loss from a wholly-owned subsidiary is deemed to be the loss of a parent from its tax year starting after the commencement of the winding-up.

Note

This election is only applicable for wind-ups under 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*, and the deemed provision is only for the tax years that start after the commencement of the wind-up.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses – losses that can be carried forward over 20 years

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	576,988		576,988	N/A		
1st preceding taxation year 2010-12-31		N/A		N/A			
2nd preceding taxation year 2009-12-31		N/A		N/A			
3rd preceding taxation year 2008-12-31		N/A		N/A			
4th preceding taxation year 2007-12-31		N/A		N/A			
5th preceding taxation year 2006-12-31		N/A		N/A			
6th preceding taxation year 2005-12-31		N/A		N/A			
7th preceding taxation year 2004-12-31		N/A		N/A			
8th preceding taxation year 2003-12-31		N/A		N/A			
9th preceding taxation year 2002-12-31		N/A		N/A			
10th preceding taxation year 2001-12-31		N/A		N/A			
11th preceding taxation year 2000-12-31		N/A		N/A			
12th preceding taxation year 1999-12-31		N/A		N/A			
13th preceding taxation year 1999-03-31		N/A		N/A			
14th preceding taxation year 1998-03-31		N/A		N/A			
15th preceding taxation year 1997-03-31		N/A		N/A			
16th preceding taxation year 1996-03-31		N/A		N/A			
17th preceding taxation year 1995-03-31		N/A		N/A			
18th preceding taxation year 1994-03-31		N/A		N/A			
19th preceding taxation year 1993-03-31		N/A		N/A			
20th preceding taxation year 1992-03-31		N/A		N/A			*
Total		576,988		576,988			

* **This balance expires this year and will not be available next year.**

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270				
Deduct: Ontario small business deduction (from schedule 500)	402				
Subtotal			►		A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)					C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")					E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")					F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")					G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)					I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	3,000			
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		3,000	►	3,000	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	-3,000	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	-3,000

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

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 (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate % ****	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) *****	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1		16,252,382	1,577,595		0	788,798	17,041,179	4	0	0	681,647	17,148,330
2.	2		592,449			0		592,449	6	0	0	35,547	556,902
3.	3		823,336			0		823,336	5	0	0	41,167	782,169
4.	6		2,905,481	118,540		0	59,270	2,964,751	10	0	0	296,475	2,727,546
5.	8		815,733	193,069		0	96,535	912,267	20	0	0	182,453	826,349
6.	10		149,749	178,154		0	89,077	238,826	30	0	0	71,648	256,255
7.	12		263	4,280		0	2,140	2,403	100	0	0	2,403	2,140
8.	13	Hillsport Water Well		19,446		0		19,446	NA	0	0	486	18,960
9.	13	Oba Water Well		27,824		0		27,824	NA	0	0	2,782	25,042
10.	17		7,773,773	2,533,263		0	1,266,632	9,040,404	8	0	0	723,232	9,583,804
11.	42		247,751			0		247,751	12	0	0	29,730	218,021
12.	43.1		1,253			0		1,253	30	0	0	376	877
13.	45		4,049			0		4,049	45	0	0	1,822	2,227
14.	47		2,771,584	568,147		9	284,069	3,055,653	8	0	0	244,452	3,095,270
15.	50		3,299	1,182		0	591	3,890	55	0	0	2,140	2,341
		Totals	32,341,102	5,221,500		9	2,587,112	34,975,481				2,316,360	35,246,233

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Hydro One Inc.		86999 4731 RC0001	1					
2.	Hydro One Networks Inc.		87086 5821 RC0001	3					
3.	Hydro One Telecom Inc.		86800 1066 RC0001	3					
4.	Hydro One Telecom Link Limited		88786 7513 RC0001	3					
5.	Hydro One Brampton Networks Inc.		86486 7635 RC0001	3					
6.	Hydro One Lake Erie Link Managem		87892 1519 RC0001	3					
7.	Hydro One Lake Erie Link Company		87560 6519 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11) Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability	7,613,460		574,201		8,187,661
2	RRPP Rev Var (427191)	3,931,806			833,706	3,098,100
3	Environmental Liability	8,291,866		6,287,428		14,579,294
4						
	Reserves from Part 2 of Schedule 13					
	Totals	19,837,132		6,861,629	833,706	25,865,055

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Networks Inc	483 Bay Street 8th Floor Toronto ON CA M5G 2P5			1,003,040		

T2 SCH 14 (99)

Canada

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SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	2,138,783	1059104			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	2,138,783	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	2,138,783	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (06)

Canada

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	Hydro One Inc.	86999 4731 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
BRIAN SOARES	(416) 345-6782

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 8,578,998

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$ \ 400{,}000}{\$ \ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$ \ 400{,}000}{\$ \ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	**B** Name of qualifying co-operative education program **405**
1.	Lakehead University	Mechanical Engineer

	C Name of student **410**	**D** Start date of WP (see note 1 below) **430**	**E** End date of WP (see note 2 below) **435**
1.	Student 1	2011-05-02	2011-09-17

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	20,113	25.000 %		20

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	5,028	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 3,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

2009 BOARD APPROVED VS. 2009 ACTUALS OM&A VARIANCE EXPLANATIONS

The following table compares 2009 actual costs versus 2009 Board approved costs for OM&A.

OM&A Cost Categories	**2009 Actuals** ($000s)	**2009 Board Approved** ($000s)	**Variance** ($000s)
Generation - Maintenance	4,277	5,803	(1,526)
Generation – Operations	3,517	3,445	72
Fuel	18,359	21,649	(3,290)
Distribution	1,378	1,648	(270)
Customer Care	1,143	1,230	(87)
Bad Debt	(365)	575	(940)
Community Relations	394	599	(205)
Shared Services & Other Costs	1,266	981	285
External Costs	156	90	66
Total OM&A	30,125	36,020	(5,895)

Remotes' actual OM&A costs were $30,125 thousand compared to $36,020 thousand approved by the Board in the EB-2008-0232 Decision with Reasons, a decrease of $5,895 thousand. The majority of this differential comes from lower fuel prices (-$3,290 thousand), lower generation maintenance, lower customer care, distribution and community relations partly offset by higher external costs and shared services and other costs.

Fuel costs were lower than plan due (-$3,290 thousand) to decreased fuel prices, improved winter road delivery and a later than planned start to servicing Marten Falls. Generation maintenance was lower than plan (-$1,526 thousand) due to lower planned engine maintenance tank farm maintenance, and corrective maintenance projects. This is discussed further in Exhibit C1-2-2.

Distribution was lower than plan ($270 thousand) due to the delay in servicing Marten Falls, lower trouble calls and lower planned maintenance offset by higher data collection and system condition assessment expenses.

Customer Care expenses were lower than plan (-$87 thousand) due to lower meter reading and reverification costs and more efficient collections. Bad debt was lower than plan related to the successful negotiation of arrears payment plans with First Nation communities. This is discussed further in Exhibit C1, Tab 2, Schedule 4.

Community Relations expenses were lower than approved ($205 thousand) due to lower customer survey costs, lower Customer Advisory Board meeting expenses and fewer community meetings.

Shared Services and Other Costs were $285 thousand higher primarily relating to one-time participation costs associated with the implementation of a corporate software project ($208 thousand), costs associated with the 2008 Cost of Service proceeding ($54 thousand) and a lower transfer of overheads to capital.

RATE BASE

1.0 INTRODUCTION

This exhibit provides the forecast of Remotes' rate base for the 2013 test year and provides a detailed description of each of the rate base components.

In accordance with the 2006 Electricity Distribution Rate Handbook ("Handbook") and the "Filing Requirements" revised by the Board on June 28, 2012, 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 $41,090 thousand.

Table 1
Remotes Rate Base ($000s)

Description	Test 2013
Gross Plant	60,084
Accumulated Depreciation	(24,740)
Net Plant	**35,344**
Cash Working Capital	5,746
Distribution Rate Base	**41,090**

[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

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 $261 thousand (0.5% of revenue requirement) are filed at Exhibit D2, Tab 2, Schedule 3.

Continuity schedules are provided in Exhibit D2, Tab 3, Schedules 1 through 3.

Table 2
Continuity of Fixed Assets Summary ($000s)

Description	Historic			Bridge	Test
	2009	2010	2011	2012	2013
Opening Gross Asset Balance	45,008	48,966	49,521	52,622	58,973
In-Service Additions	4,943	3,657	5,898	7,304	7,486
Retirements	(981)	(3,095)	(2,797)	(953)	(5,264)
Transfers	(4)	(7)	-	-	-
Closing Gross Asset Balance	48,966	49,521	52,622	58,973	61,195
Mid Year Gross Asset Balance	46,987	49,244	51,072	55,798	60,084

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 2010 include the retirement of major assets replaced during the Sandy Lake and Gull Bay upgrades. There were higher engine retirements in 2011 along with the Sandy Lake and Webequie staff houses. The increase in 2013 reflects the retirement of assets related to the Shoulderblade Falls hydro-electric generating station which will be transferred to the First Nation.

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 13% of eligible OM&A expenses per the Filing Requirements for Electricity Transmission and Distribution Applications, issued June 28, 2012. A detailed calculation is found in Exhibit D2, Tab 4, Schedule 1.

Table 3

Working Capital Calculation	($000s)
Total Eligible OM&A Expenses	44,199
Working Capital Allowance @ 13.0%	5,746

REMOTES' DISTRIBUTION AND GENERATION ASSETS

1.0 INTRODUCTION

At December 31, 2011, Remotes managed net fixed assets of $28,494 thousand to provide the safe and reliable generation and delivery of electricity to 3,533 customers in 21 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-hydroelectric 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 57 diesel generators in service, ranging in size from 65kW to 1250kW. 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.

3.0 KEY CHARACTERISTICS OF THE DISTRIBUTION SYSTEM

Remotes operates 19 isolated distribution systems to serve the 21 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 233 kilometers of line, 4610 wood poles, 1,122 transformers (used for voltage transformation) and 265 switches distributed throughout the system. 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 beginning to age, having been 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.

4.0 KEY CHARACTERISTICS OF FACILITIES

Remotes has a Service Centre in Thunder Bay, Generating Station buildings in 19 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 (now Aboriginal Affairs and Northern Development Canada "AANDC"), AANDC funds new generation and distribution capital within First Nation communities served by Remotes. Remotes ultimately takes ownership of these assets, although they are not included in rate base or revenue requirement as they have a nominal carrying value because they are provided as contributed capital. In non-First Nation communities, a similar arrangement exists, except that the provincial government funds the original capital costs of the plants.

Remotes' ongoing capital expenditures relate primarily to asset and equipment replacements required to safely and reliably deliver electricity to the 21 communities in its service territory. Remotes invests in assets as replacements are required due to end-of-life, equipment failure, to meet new standards or to improve the overall operations and efficiency of the plant when an upgrade is not planned.

As indicated in Exhibit A, Tab 4, Schedule 1, in 2011, AANDC informed Remotes that it is facing funding constraints and does not have funding for required upgrades in its current 5-year capital plan. Because federal funding for new stations is expected to be delayed, Remotes' capital expenditures related to generation and facility asset replacement and refurbishment is expected to increase in the near to medium term.

An overview of Remotes' capital investments for the historic and bridge years and proposed investments for the test year is provided in Table 1 below.

Table 1
ANNUAL CAPITAL INVESTMENTS
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Generation	3,135	2,488	4,575	4,891	4,555
Distribution	195	620	476	522	707
Facilities	909	269	1,997	851	773
Minor Fixed Assets	34	167	181	100	100
Total	4,273	3,544	7,229	6,364	6,135

Remotes capitalizes costs that are directly attributable to the acquisition and construction of capital projects. Remotes also capitalizes certain overhead and indirect costs that are causally or beneficially related to supporting its capital projects. With the Board's approval of US GAAP as the basis for regulatory accounting and rate setting for Remotes, the Company will continue to capitalize attributable overhead costs consistent with its legacy approach previously applied to the historic years under Canadian generally accepted accounting principles (CGAAP).

In the Board's Decision with Reasons for the EB-2011- 0268 proceeding, Hydro One Networks Inc.was directed to conduct a critical review of its current and proposed capitalization practices. This review can be seen at EB-2012-0031 Exhibit C1, Tab 7, Schedule 2, Attachment 2. In its Decision with Reasons on Remotes' request to adopt US GAAP in place of modified International Financial Reporting Standards as its approved basis of regulatory accounting and reporting (EB-2011- 0427), the Board observed that "Board staff noted that Hydro One uses the same capitalization policies across all of its regulated businesses and submitted that the results of this capitalization review, as it pertains to Remotes, should be included in its next cost of service application." In its Findings, the Board noted "that Hydro One has indicated that it would apply the results of the capitalization review to its Remotes business. The Board expects that the impacts of this review will be addressed in the next Remotes cost-of-service rate application." In its critical review of the appropriateness of its overhead capitalization policy for Networks Transmission, no policy changes were recommended. As a result, no changes have been reflected in this cost-of-service application related to Remotes' legacy CGAAP approach to capitalizing overheads and indirect costs.

The Remotes' overhead capitalization rate is a calculated percentage representing the amount of CCFS overhead costs that are required to support capital projects in a given year. Specifically, this rate reflects the total CCFS amounts to be capitalized as a percentage of total capital expenditures. CCFS amounts to be capitalized are determined based a 3-year average of direct capital expenditures as a percentage of the total capital and OM&A work program. The overhead capitalization rate for 2013 is 5.5%.

The following table shows capitalized overheads, and the related overhead capitalization rates for the Historical, Bridge and Test Years. This information may also be seen in Exhibit C1-2-6, Table 1.

Table 2
Overhead Capitalization
Historical, Bridge and Test Year

	Historic			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Total capitalized overheads ($000s)	371	359	495	391	455
Capitalized overhead rate (%)	6.4	7.6	5.7	5.5	5.5

Remotes' capital programs fall into three main categories: generation, distribution and facilities. Remotes plans its capital investments in accordance with customer requirements and good utility practice, in order to maintain or improve safety and reliability, and to ensure that it is compliant with regulatory requirements and operational standards.

2.0 GENERATION CAPITAL PROGRAMS

2.1 Planned Capital Replacement of Diesel Engines and Auxiliary Systems

Table 3
ENGINE AND AUXILIARY OVERHAULS AND REPLACEMENTS
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Engine and Auxiliary System Replacements	2,062	1,336	3,586	2,218	3,056

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 32,000 to 40,000 hours for 1200 RPM units.

The frequency and timing of major engine overhauls are planned in accordance with manufacturer's procedures and are based on the hours an engine has run. Annual engine run times vary for each unit, typically in the range of 2,500 to 4,500 hours per year. 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. As necessary, minor auxiliary work is undertaken when engines are overhauled.

In general terms, Remotes has determined that diesel engine-generator sets should be replaced after two rebuilds (three complete life cycles). As a result, an engine may be 12 to 18 years old when it is replaced. Some units may be identified for earlier replacement subject to specific issues discovered during its life cycle. Replacement may be advanced or lengthened accordingly. The new units incorporate current emission reduction technology and improved fuel efficiency.

The engine replacement program also includes major work related to auxiliary systems. Auxiliary work is evaluated on a case-by-case basis given the site, the existing equipment in service and the proposed replacement. When integrating new engines into older existing systems, heating, cooling, ventilation, exhaust, electrical, fuel and control systems may be impacted. Performing all necessary auxiliary work when engines are replaced reduces engine downtime, mobilization and travel costs.

Year-over-year variances relate to the timing of required engine replacements based on engine hours, the size of the units being replaced as larger engines are more expensive to replace, and improvements to the planning and procurement process starting in 2011 to reduce the risk of missing winter roads.

2.2 Emergency System Breakdowns

Table 4
EMERGENCY SYSTEM BREAKDOWNS
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Emergency System Breakdowns	2	43	15	0	0

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. Since 2009, emergency system breakdowns have been reduced significantly from historical levels as a result of improved maintenance. Because of the inherent uncertainty of costs and budgeting associated with catastrophic failures, emergency system breakdowns are no longer included in Remotes' business plan. While preventive maintenance can control and reduce failure rates, equipment failures may still occur. Minor breakdowns would be addressed in the engine replacement program. Catastrophic failures would be treated as unforeseen expenditures.

2.3 Upgrade Projects

Table 5
UPGRADE PROJECTS
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Upgrade Projects	178	0	0	0	0

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 contributed to these legacy projects. 2009 reflects costs associated with the upgrade in Gull Bay, which was initiated prior to 2005.

2.4 Tank Farm Upgrades

Table 6
TANK FARM UPGRADES
($000s)

	Historic			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Tank Farm Upgrades	12	104	268	1,256	0

Tank farm upgrades are projects designed to comply with safety and environmental regulations and to maintain station reliability. Tanks farms are regularly monitored and inspected. Projects to address compliance and improvements are planned as needed. 2012 projects include improvements at Weagamow ($600 thousand) to address deficiencies associated with the fuel storage tanks, and to address deficiencies at the Landsdowne tank farm ($440 thousand), and modifications to the day tanks in Sultan ($210 thousand) to comply with current Regulations. No projects are planned for 2013.

2.5 Generation Improvement

Table 7
GENERATION IMPROVEMENT CAPITAL
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Generation Improvement	881	1,005	706	1,417	1,499

The Generation Improvement Capital program encompasses project based capital investments that are designed to improve the operations of the generating stations to meet environmental and safety standards and to improve the efficiency of operations. Projects vary year over year depending on changing standards, issues identified through monitoring and compliance reviews, and initiatives identified to improve station performance. Similarly, program spending varies year over year depending on the complexity of the project and level of work required. The major projects in 2009 included the design and construction of an environmental treatment facilities required to clean up a spill in Kingfisher Lake and enhancements to engine room containment to reduce the risk of future spills ($710 thousand). In 2010, major program activity related to the installation of spill detection systems ($470 thousand), Shoulderblade Falls optimization ($115 thousand), and work related to the Armstrong Flu-Gas Analysis System ($200 thousand). In 2011, major projects included control modifications in Gull Bay to improve the station operation ($118 thousand) and site work to install a windmill in Kasabonika Lake ($340 thousand). The major 2012 projects include Supervisory Control and Data Acquisition (SCADA) and Programmable Logic Computer (PLC) system replacements ($430 thousand) needed to replace and improve the existing plant communications and automation systems, and Protection Upgrade/Switchgear work ($160 thousand), needed to improve safety at the plants. The major 2013 projects include ventilation system improvements ($220 thousand), design and replacement of plant fire suppression systems ($260 thousand), Protection Upgrade/Switchgear work ($184 thousand), SCADA and PLC replacement projects ($282 thousand) and Spill Containment Enhancements ($225 thousand).

3.0 DISTRIBUTION CAPITAL PROJECTS

3.1 Metering, Minor Storm Damage, Damage Claims and Small External Demand Requests

Table 8
METERING, MINOR STORM DAMAGE, DAMAGE CLAIMS AND SMALL EXTERNAL DEMAND REQUESTS
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Metering, Minor Storm, Damage Claims and Small External Demand	156	75	33	75	133

Investments under the Metering, Minor Storm Damage and Damage Claims, and Small External Requests Programs are driven by reliability, customer satisfaction and regulatory compliance.

Investments in metering are driven by regulatory compliance with Measurement Canada rules. 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. Damage Claims and small External Demand Requests 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. Small external demand requests are related to Joint Use work in association with Bell and local First Nation attachments and are normally fully recoverable.

The implementation of a cyclical forestry clearing in 2008 and 2009 reduced minor storm damage work in 2010 and 2011. In 2011 Measurement Canada requirements meant that a large number of meters needed to be changed. Increases in 2013 are related to anticipated meter deployment in Pikangikum and Cat Lake

3.2 Distribution System Improvements

Table 9
DISTRIBUTION SYSTEM IMPROVEMENTS
($000s)

	Historic			Bridge	Test
	2009	**2010**	**2011**	**2012**	**2013**
Distribution System Improvements	20	492	395	447	574

Distribution System Improvements include planned improvements and component replacements required to maintain the operation of distribution lines and associated facilities. Asset Condition Inspections 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*.

Distribution capital in 2009 was lower due to most of the work being recoverable work. Variances between 2010 and 2011 relate primarily to a large betterment project in Sachigo Lake in 2010 ($90 thousand). Distribution variances between bridge and test year reflect anticipated costs associated with taking over service to the communities of Cat Lake and Pikangikum ($60 thousand).

4.0 FACILITIES CAPITAL

Table 10
FACILITIES CAPITAL
($000s)

	Historic			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Facilities	909	269	1,997	851	773

Remotes has an ongoing 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.

Garage and house structures could not be transported by winter road for construction in 2010 leading to lower than usual investments. Increased investments in facilities in 2011 relate to the replacement of staff houses in Sandy Lake, Fort Severn and Webequie.

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), referred to as Allowance for Funds Used During Construction (AFUDC), reflects the Board's Decision in proceeding EB-2006-0117. This Decision required that the interest rate to be used for CWIP would be the Scotia Capital All-Corporates Mid-Term Average Weighted Bond Yield, as published on the Bank of Canada website and updated quarterly. Per the OEB's website, since July 2007, "the source reference for the CWIP interest rate, the Scotia Capital Inc. All-Corporates Average Weighted Yield Mid-Term, has not been publicly available via the Bank of Canada's website". This bond yield has been renamed as the "DEX Mid-Term Corporate Bond Index".

The rates used in calculating AFUDC for the bridge and test years were derived using US GAAP. The historical years 2009 to 2011 reflect the average quarterly prescribed interest rate.

Table 1
Allowance for Funds Used During Construction

Year	AFUDC Rate	AFUDC ($ thousands)
2009	5.9%	156
2010	4.3%	126
2011	4.2%	166
2012	4.8%	245
2013	4.3%	266

HYDRO ONE REMOTE COMMUNITIES INC
Statement of Utility Rate Base
Forecast Year (2013)
Year Ending December 31
($000s)

Line No.	Particulars		2013
	Electric Utility Plant		
1	Gross plant at cost	$	60,084
2	Less: accumulated depreciation		(24,740)
3	Net plant in service	$	35,344
4	Cash working capital	$	5,746
5	Total rate base	$	41,090

HYDRO ONE REMOTE COMMUNITIES INC.
COMPARISON OF CAPITAL EXPENDITURES - HISTORIC, BRIDGE AND TEST YEARS

		2009	2010	2011	Bridge 2012	Test 2013
Generation						
	Planned Capital Replacement of Diesel Engines & Aux Equipment	2,062	1,336	3,586	2,218	3,056
	Emergency System Breakdowns inc. Temp Units	2	43	15	0	0
	Upgrade Projects	178	0	0	0	0
	Fuel Tank Farm Upgrade Projects	12	104	268	1,256	0
	Generation Improvement Capital	881	1,005	706	1,417	1,499
	Total "Generation"	**3,135**	**2,488**	**4,575**	**4,891**	**4,555**
Distribution						
	Metering, Minor Storm Damage & Damage Claims	156	75	33	75	133
	Fixed Price Layouts, New Customer Connections & Service Upgrades	19	53	48	0	0
	Distribution System Improvements	20	492	395	447	574
	Total " Distribution"	**195**	**620**	**476**	**522**	**707**
Facilities						
	Planned	909	269	1,997	851	773
	Total "Facilities"	**909**	**269**	**1,997**	**851**	**773**
Minor Fixed Assets		34	167	181	100	100
	Overall Total	**34**	**167**	**181**	**100**	**100**
TOTAL REMOTES CAPITAL		**4,273**	**3,544**	**7,229**	**6,364**	**6,135**

Notes:

"Upgrade Projects" expenditures fully recoverable
Generation Improvement Capital include non-routine projects
New customer connections budgeted as fully recoverable in bridge and test year(s)
Planned capital replacement of diesel engines include capital engine overhauls
Except where a cost share agreement was in place

LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $261K TEST YEAR - 2013

1.0 INTRODUCTION

As outlined in Exhibit A, Tab 14, Schedule 2, Program and Project Approval, Asset Planning Documents ("APD'S") are prepared and approved as part of the business planning process. Approvals for facilities projects are prepared during the budgeting process when the project scope is determined. The filing requirements require written documentation for capital projects for programs and projects in excess $261 thousand (0.5% of revenue requirement). Remotes' internal program and project approval documentation is based on gross capital, including removals and capital contributions. As discussed in Exhibit D1, Tab 2, Schedule 1, Remotes does not include contributed capital in its rate base; as such, net capital is shown in those exhibits. The cost of removals associated with these projects can be found in the continuity schedule in Exhibit D2, Tab 3, Schedule 1. Because Remotes internal documentation is s based on gross capital, gross capital is shown on the attachments to this exhibit.

2.0 GENERATION CAPITAL (EXHIBIT D1, TAB 1, SCHEDULE 2)

	$000s
Engine and Auxiliary Replacements (D2-2-3 Att.1)	2,818
Engine Overhauls[1] (D2-2-3 Att. 2)	238
SCADA & PLC Replacements[2]	282

[1] Capital spending associated with Engine and Auxiliary Overhauls and Replacements is shown on a consolidated basis in Exhibit D1-2-1.
[2] For specific improvement projects business cases are only completed during detailed budgeting process as discussed in Exhibit A, Tab 14 Schedule 2.

<u>Summary</u>

Total Generation projects/programs listed above	3,338
All other Generation projects/programs	1,217
Total Generation capital (per Exhibit D1-2-1)	4,555

3.0 DISTRIBUTION CAPITAL (EXHIBIT D1, TAB 1, SCHEDULE 2)

	$000s
Distribution System Improvements (D2-2-3 Att. 3)	574

<u>Summary</u>

Total Distribution projects/programs listed above	574
All other Distribution projects/programs	133
Total Distribution capital (per Exhibit D1-2-1)	707

4.0 FACILITIES CAPITAL (EXHIBIT D1, TAB 1, SCHEDULE 2)

	$000s
Planned Facility Improvements[3]	517

<u>Summary</u>

Total Facilities projects/programs listed above	517
All other Facilities projects/programs	256
Total Facilities capital (per Exhibit D1-2-1)	773

[3] For specific facilities projects business cases are only completed during detailed budgeting process as discussed in Exhibit A, Tab 14 Schedule 2.

5.0 MINOR FIXED ASSETS (EXHIBIT D1, TAB 1, SCHEDULE 2)

	$000s
Minor Fixed Assets	100

	$000s
Total Capital Expenditures	**$6,135**

JUSTIFICATION FOR PROGRAMS/PROJECTS IN EXCESS OF 261K[1]

Attachment 1: Justification for Generation Capital Sustainment (Engine and Auxillary Replacement)

Attachment 2: Justification for Generation Capital Sustainment (Engine Overhauls)

Attachment 3: Justification for Distribution Capital Sustainment

[1] Does not include future use assets

1. Generation Capital Sustainment

Planned Capital Replacement of Engines (now excludes Engine Overhauls)

- ***Driver Description***

Diesel engine-generator sets ("gensets") are maintained as per manufacturers' published recommendations, including complete overhauls after specified hours. Medium speed (1800 rpm) units are rebuilt after 20,000 hours, low speed (1200 rpm) units after 32,000 to 40,000 hours.

In general terms, Remotes has determined that a genset should be replaced after two rebuilds (ie. three complete life cycles). Some units may be identified for earlier replacement subject to specific issues discovered during its life cycle. Replacement may be advanced or lengthened accordingly.

- ***Highlights***

Remotes has sixty-three (63) genset units (at time of writing) available for operation in the nineteen (19) generating stations. Each station has between two to four engines per community, ranging in size from 85 kW to 1,250 kW.

Engine run hours determine when a unit is due for overhaul, which is in accordance with the manufacturer's recommended parts replacement. The programmable logic controller (PLC) program selects the most fuel-efficient engine(s) to run at any given time based on the community load so engines receive inconsistent lengths of run time.

Annual engine run times vary for each unit, typically in the 2,500 to 4,500 hours per year. An engine may be twelve to eighteen years old when it is replaced. There are improvements in fuel economy and emissions performance with the new units.

The engine replacement program also includes work related to auxiliaries. Auxiliary work is evaluated on a case-by-case basis given the site, the existing equipment in service and the proposed replacement. When integrating new engines into older existing systems; heating, cooling, ventilation, exhaust, electrical, fuel and control systems may be impacted. It is preferred that all necessary auxiliary work be done in conjunction with the engine replacements in order to reduce engine down-time, mobilization and travel costs.

In lieu of a third engine overhaul, a replacement genset is ordered in advance of winter roads where necessary and replacement is carried out instead of the third overhaul.

In the past, strong community load growth has triggered frequent station upgrades which involve replacing gensets prior to them reaching their full life term.

- ***Plan over Plan Current***

Plan Over Plan Current (Gross)

	2011	2012	2013	2014	2015	2016
BP2011-2015	2,169,097	2,238,737	1,398,350	1,777,106	1,778,388	1,778,388
BP2012-2016	2,919,152	2,207,653	3,131,579	1,617,196	1,622,460	1,628,036
Difference	750,055	(31,084)	1,733,229	(159,910)	(155,928)	(150,352)

- ***Year over Year Current***

Year Over Year Current (Gross)

	2010 Actual	2011 Actual	2012	2013	2014	2015	2016
BP2012-2016	866,847	2,919,152	2,207,653	3,131,579	1,617,196	1,622,460	1,628,036
Difference		2,052,305	(711,499)	923,926	(1,514,383)	5,264	5,576

The number and size of generators that come up for replacement due to operating hours is predicted using forecasting techniques. Each year, the future operating hours are estimated based upon community load forecasts, and added to the engines' actual past performance. The number of units due for replacement in a given year varies because of a number of operational factors leading to year over year variances which are normal for this program.

- ***Current Risk Profile***

□ Financial
□ Regulatory Relationship
X Efficiency
□ Reputation
X Customer/Reliability
X Safety & Environment

- ***Asset Planning***

Genset replacements result in asset removal and retirement. The removed generation sets are brought back from site and sent off to investment recovery. Occasionally they may be used for spare parts (ie. generator) in the case of obsolete units, etc.

- ***Proposed Accomplishments***

Renewing the gensets instead of rebuilding for a third time keeps the genset mix "more modern". In addition to the aforementioned fuel efficiency and reduced emissions benefits, parts are more readily available, and engine controls more compatible within stations receiving upgrades.

2. Generation Capital Sustainment

Engine Overhauls

- ***Driver Description***

Diesel engine overhaul/rebuild based on engine manufacturer's preventative maintenance procedures. These overhauls are scheduled to occur when engine hours reach 20,000 for 1800 RPM and 40,000 for 1200 RPM engines.

- ***Highlights***

Engine overhauls are carried out on site in the Remote Communities. There are approximately 63 gen-set units available for operation in the 19 generating stations. The diesel gen-sets range in size from 85kW to 1,000kW. The diesel plants have between 2 and 4 engines per community. 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.

- ***Plan over Plan Current***

Plan Over Plan Current (Gross)

	2011	2012	2013	2014	2015	2016
BP2011-2015	0	261,473	269,651	277,770	286,898	292,923
BP2012-2016	700,444	257,144	264,399	272,194	280,222	289,328
Difference	700,444	(4,329)	(5,252)	(5,576)	(6,676)	(3,595)

2011 projections include a major overhaul of the largest unit in Kasabonika and in Armstrong. Delays in the capital upgrade of Kasabonika plant have changed the running times of engines and have pushed the major overhaul forward.

- ***Year over Year Current***

Year Over Year Current (Gross)

	2010 Actual	2011 Actual	2012	2013	2014	2015	2016
BP2012-2016	0	700,444	257,144	264,399	272,194	280,222	289,328
Difference		700,444	(443,300)	7,255	7,795	8,028	9,106

In conjunction with engine replacement program, future amounts are expected to reduce to a more historical level following the 2011 spike.

- ***Current Risk Profile***

□ Financial	**□ Reputation**
□ Regulatory Relationship	**X Customer/Reliability**
X Efficiency	**X Safety & Environment**

- ***Asset Planning***

Engine overhauls cover major component replacement on the diesel generating sets to extend/renew asset life.

- ***Proposed Accomplishments***

3. Distribution Capital Sustainment

Distribution System Improvements

- ***Driver Description***

The drivers for this investment are reliability and regulatory. Distribution system improvements include planned improvements and component 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 Bell attachments. 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.

- ***Highlights***

Replace aging and defective poles as determined by asset condition surveys. Perform betterments and system upgrades to facilitate system reliability and accommodate joint use.

- ***Plan over Plan Current***

Plan Over Plan Current (Gross)

	2011	2012	2013	2014	2015	2016
BP2011-2015	379,007	386,052	396,093	406,104	418,113	418,113
BP2012-2016	838,051	704,246	794,761	867,393	795,849	808,973
Difference	459,044	318,194	398,668	461,289	377,736	390,860

Analysis from information gathered during recent asset condition assessments has determined that a number of poles are required to be replaced over the planning period. This replacement requirement has resulted in a required increase in funding to sustain a systematic replacement program to ensure reliability. As well, expected system expansion into the communities of Pikangikum and Peawanuk (2013 and 2014) have resulted in the need for additional funds.

- ***Year over Year Current***

Year Over Year Current (Gross)

	2010 Actual	2011 Actual	2012	2013	2014	2015	2016
BP2012-2016	532,341	838,051	704,246	794,761	867,393	795,849	808,973
Difference		305,710	(133,805)	90,515	72,632	(71,544)	13,124

This work varies year to year based on the size, nature, and volume of joint use activity and asset degradation. The Lansdowne teardown was advanced from 2012 to 2011 to allow for Bell to accomplish their work during the summer of 2011.

- ***Current Risk Profile***

□ Financial
X Regulatory Relationship
□ Efficiency
□ Reputation
X Customer/Reliability
□ Safety & Environment

- ***Asset Planning***

Replacement of capital units will be determined by asset condition surveys and system enhancement evaluation to ensure reliability and joint use requests.

- ***Proposed Accomplishments***

Pole replacements in several communities as a result of noted defects during MDx data collection.

HYDRO ONE REMOTE COMMUNITIES INC

Mapping In-Service Additions to Grouped USofA Accounts

Year Ending December 31
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013) Years
($000s)

			Historical			Bridge	Test
Line No.	**Minimum USoA Grouping**	**Account Numbers**	**2009**	**2010**	**2011**	**2012**	**2013**
1	Land and Buildings	1805, 1806, 1808, 1810, 1905, 1906	4	-	-	-	-
2	TS Primary Above 50	1815	-	-	-	-	-
3	Distribution Station Equipment	1820	-	-	-	-	-
4	Poles, Wires	1830, 1835, 1840, 1845	199	243	340	320	397
5	Line Transformers	1850	27	93	76	112	137
6	Services and Meters	1855, 1860	125	100	85	55	101
7	General Plant	1908, 1910	412	616	1,542	1,212	503
8	Equipment	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960	31	141	181	84	84
9	IT Assets	1920, 1925	7	26	-	16	16
10	Generation Plant	1615, 1620, 1650, 1665, 1670,1675, 1680, 1685, 1970, 1975, 1980, 2005	4,138	2,438	3,674	5,504	6,248
11	Smart Meters		-	-	-	-	-
12	**Total In-Service Assets**		**4,943**	**3,657**	**5,898**	**7,304**	**7,486**

HYDRO ONE REMOTE COMMUNITIES INC.
Continuity of Property, Plant and Equipment
Year Ending December 31
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013) 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	2009	45,008	4,943	(980)	(4)		48,966	46,987
2	2010	48,966	3,657	(3,094)	(7)		49,521	49,244
3	2011	49,521	5,898	(2,797)			52,622	51,072
Bridge								
4	2012	52,622	7,304	(953)			58,973	55,798
Test								
5	2013	58,973	7,486	(5,264)			61,195	60,084

HYDRO ONE REMOTE COMMUNITIES INC.
Continuity Accumulated Depreciation
Year Ending December 31
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013) 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	2009	22,623	2,654	(980)	(1)			24,297	23,460
2	2010	24,297	2,815	(3,094)	(3)			24,014	24,155
3	2011	24,014	2,909	(2,794)	(1)			24,128	24,071
Bridge									
4	2012	24,128	2,898	(953)	-	-		26,074	25,101
Test									
5	2013	26,074	2,596	(5,264)	-	-		23,406	24,740

HYDRO ONE REMOTE COMMUNITIES INC.
Continuity of Construction Work in Progress
Year Ending December 31
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013) 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	2009	3,020	4,297	(4,911)		2,406
2	2010	2,406	3,377	(3,490)		2,293
		2,406				
3	2011	2,293	7,102	(5,716)		3,679
Bridge						
4	2012	3,679	6,264	(7,204)		2,739
Test						
5	2013	2,739	6,035	(7,386)		1,388

HYDRO ONE REMOTE COMMUNITIES INC.

Statement of Working Capital

Test Year (2013)

($000s)

Line No.	Particulars		2013
	OM&A Expenses		
1	Generation	$	36,632
2	Distribution		3,580
3	Billing and Collecting		1,903
4	Community Relations		866
5	Administrative & General		1,157
6	External Costs		61
7	Total Eligible OM&A	$	44,199
8	Working Capital Factor		13%
9	**Working Capital Allowance**	**$**	**5,746**

2009 BOARD APPROVED VS. 2009 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)	**2009 Actuals** ($ thousand)	**2009 Board Approved** ($ thousand)	**Variance** ($ thousand)
Distribution	195	641	(446)
Facilities	909	639	270
Generation	3,135	3,758	(623)
Minor Fixed Assets	34	100	(66)
Total	4,273	5,138	(865)

Minor fixed assets include computer (IT) equipment, office furniture and equipment, service equipment and transport and work equipment.

Remotes' capital expenditures in 2009 were $4,273 thousand compared to $5,138 thousand approved by the Board for 2009.

Distribution planned maintenance was lower than plan due to a large number of requests for new customer connections, which is largely recoverable work. Facilities spending was higher than plan due to the decision to complete a higher number of station lighting projects than planned.

Factors contributing to lower generation spending in 2009 actual vs Board approved were lower emergency system breakdowns (-$540), the deferral of road site improvement projects to future years due to reprioritization of work (-$420 thousand), the deferred replacement of Supervisory Control and Data Acquisition and Programmable Logic Controller systems as the new systems were not compatible with existing hardware (-$280 thousand), the deferral of the implementation of Protection Upgrades due to reprioritization of work (-$240 thousand) and the redeployment of engineering staff from the Armstrong Zero Emissions project (-$350 thousand) and the Big Trout Lake Tank Farm improvement project (-$280 thousand) to the construction of the Kingfisher Pump and Treat System ($570 thousand) and the Engine Room Containment project ($150 thousand). Lower generation spending was also offset by higher replacements/rebuilds of diesel engines and equipment ($460 thousand).

2.0 RATE BASE

Rate Base Component ($ Thousands)	2009 Actuals	2009 Board Approved	Variance
Gross Plant	48,966	48,319	647
Accumulated Depreciation	(24,297)	(23,608)	(689)
Net Plant	**24,669**	**24,711**	**(42)**
Cash Working Capital[1]	5,615	5,615	0
Total Rate Base	30,284	30,326	(42)

Total rate base was $42 thousand below the board approved amount, a variance of 0.14%

[1] Remotes does not calculate actual cash working capital, therefore the 2009 approved amount is used for illustrative purposes.

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	44,199	Exhibit C1, Tab 2, Schedule1
Depreciation and Amortization	6,030	Exhibit C1, Tab 4, Schedule 1
Income Taxes	(187)	Exhibit C2, Tab 5, Schedule 1, Att A
Cost of Capital (100% debt)	2,242	Exhibit B1, Tab 1, Schedule 1
Total Revenue Requirement	$52,284	Exhibit E1, Tab 1, Schedule 1
Annual RRRP	(34,510)	Exhibit G1, Tab 1, Schedule 3
Other Revenues	(514)	Exhibit E3, Tab 1, Schedule 1
Rate Revenue Requirement	$17,260	Exhibit E2, Tab 1, Schedule 1

The resultant Total Revenue Requirement of $52,284 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 and regulatory requirements. The rate revenue requirement of $17,260 thousand represents the amount to be funded through rates 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	$36,632
Distribution	3,580
Customer Care	1,903
Community Relations	866
Shared Services and Other Costs	1,157
External Costs	61
Total OM&A	**$44,199**

2.2 Depreciation and Amortization Expense

Depreciation	$3,317
Amortization	$2,713
Total Expense	**$6,030**

2.3 Payments in Lieu of Corporate Income Taxes

Income Before Payments in Lieu of Corporate Income Taxes	$(187)
Tax Rate	26.5%
Total Payments in Lieu of Corporate Income Taxes	**$(187)**[1]

2.5 Cost of Capital

Cost of Capital (100% debt)	$2,242

3.0 REVENUE REQUIREMENT – COMPARISON OF YEAR 2009 TO YEAR 2013

Table 2 below compares, by element, the Year 2009 approved Revenue Requirement (as per EB-2008-0232) against the Year 2013 proposed Revenue Requirement.

[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.

Table 2
Comparison of Revenue Requirements: 2009 vs. 2013 ($000s)

Line No	Description	Year 2009 OEB Approved	Year 2013	Difference
1	OM&A	36,016	44,199	8,183
2	Depreciation	4,469	6,030	1,561
3	Capital Tax	72	0	(72)
3	Income Taxes	0	(187)	(187)
4	Cost of Capital	1,647	2,242	595
5	**Total Revenue Requirement**	**42,204**	**$52,284**	**10,080**
6	Annual RRRP	(27,549)	(34,510)	(6,961)
7	Other Revenues	**(609)**	**(514)**	**99**
8	Rate Revenue Requirement	**$14,046**	**$17,260**	**$3,214**

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 associated with generation work program requirements ($1,337 thousand), fuel ($2,418 thousand), electricity purchases for grid-connected communities ($1,368 thousand), purchases of electricity from the Shoulderblade Falls Hydroelectric Station ($612 thousand) and increased distribution maintenance costs primarily associated with clearing the transmission line right-of-way to Cat Lake ($1,200 thousand) and with providing distribution services to Pikangikum ($380 thousand). There is also an increase in rate base as reflected in cost of capital and depreciation. These are partially offset by lower capital and income taxes.

The higher Rate Revenue Requirement for 2013 as compared to 2009 reflects the proposed 3.45% increase, Incentive Regulatory Mechanism (IRM) increases of approximately 1% in each of the past three years, and increased load growth primarily related to the inclusion of the communities of Cat Lake and Pikangikum.

HYDRO ONE REMOTE COMMUNITIES INC.
Calculation of Revenue Requirement
Year Ending December 31, 2013
($000s)

Line No.	Particulars		2013
	Cost of Service		
1	Operating, maintenance & administrative	$	44,199
2	Depreciation & amortization		6,030
3	Income taxes		(187)
4	Cost of service excluding cost of capital (Note 1)	$	50,042
5	Cost of capital		2,242
6	Service revenue requirement	$	52,284
7	Less Annual RRRP		(34,510)
8	Less Other Revenues		(514)
9	Total Rate Revenue Requirement	$	17,260

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 outstanding balances, except GST, 23 days after the billing date. The charge applies to account balances remaining 21 days after the issuance of the bill. The charge is 1.5% per month and is compounded monthly, resulting in a charge of 19.56% per annum. 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**
	2009	**2010**	**2011**	**2012**	**2013**
Energy Late Payment	244	311	231	289	314
Non-Energy Late Payment	7	46	67	25	25
Miscellaneous Distribution Revenue	26	39	33	25	25
Total	**277**	**396**	**331**	**339**	**364**

Late payment charges vary based on actual bills outstanding. The Bridge and Test Year forecasts are based on historical information and number of customers.

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 activities (streetlights 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 AANDC and the Nishnawbe Aski Development Fund. These assessments identify operational risks and efficiency measures that could be undertaken by AANDC or the local First Nation. Revenues associated with work done for Hydro One Networks under Service Level Agreements (as discussed in Exhibit A, Tab 9, Schedule 3 Appendix F are also included in external work. Revenues from external work are shown in Table 3, below.

Table 3
Revenues from External, Unregulated Work
($000s)

Historic Years			**Bridge**	**Test**
2009	**2010**	**2011**	**2012**	**2013**
356	619	421	150	150

Higher external revenues in 2010 reflect a study of the Weenusk generating station undertaken for Weenusk First Nation and AANDC during 2010 and 2011, and increased work performed for Hydro One Networks Inc. associated with training assistance, a pole replacement project and the response to the E1C fire in 2011.

Table 4
Total Other Revenues
($000s)

	Historic Years			**Bridge**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**
Late Payment and Service Charges	277	396	331	339	364
External Unregulated Work	356	619	421	150	150
Total	**633**	**1,015**	**752**	**489**	**514**

REGULATORY ACCOUNTS

1.0 DESCRIPTION OF REGULATORY ACCOUNTS

Remotes has three Regulatory Accounts: the Rural and Remote Rate Protection Variance Account RRRPP (RRRPVA); an IFRS Transition Costs Variance Account; and an Impact for USGAAP Account.

($000s)

	Historic			Bridge
Year	2009	2010	2011	2012 Projected
Rural and Remote Rate Protection (USofA 2405)	**(3,627)**	**(3,932)**	**(3,098)**	**747**
IFRS Transition Costs (USofA 1508)	**0**	**0**	**0**	**72**
Impact of USGAAP Account (USofA 1508)	**0**	**0**	**0**	**0**
Total	**(3,627)**	**(3,932)**	**(3,098)**	**819**

1.1 Remote Rate Protection Variance Account

Remotes 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 ensure breakeven results in operations is added to, or drawn from, the RRRPVA. The account was originally established in 2003 pursuant to O.Reg. 442/01. In its RP-2005-0020/EB-2005-0511 Decision, and in its Decision in EB-2008-0232, the Board approved continuation of this account. Detailed information about the balances in this account can be found as Appendices A, B, C and D attached to this exhibit.

No interest is applied to the RRRPVA given that the intent of the account is to serve as a tool to achieve a break-even operating result. Adding interest would result in a circular impact on the RRRPVA as the interest cost would itself impact that year's operating result, causing a revision to the amount added to or withdrawn from the RRRPVA.

1.2 International Financial Reporting Standards Transition Account

This account was established based on the Board's decision on Remotes' Request for approval for the use of the USGAAP accounting standard (EB-2011-0427) to record the variance between the forecast IFRS transition implementation costs and the actual costs incurred. The Board ordered that the IRFS transition amounts recorded in the RRRPVA should be removed and instead recorded in the IFRS transition account. This account is now reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

Simple interest is applied to the monthly opening principal balance in this account, according to the Board prescribed interest rate.

2.0 REQUEST FOR DISPOSITION OF ACCOUNTS

It is requested that Remotes' new rates will be effective and implemented on May 1, 2013, and that disposition of the accounts requested will commence on that date.

HYDRO ONE REMOTE COMMUNITIES INC.
Variance Account Reconciliation
For the year ended Dec. 31, 2009

		Revenues and Expenses Audited Actuals		Approved	Variance
RRRP Variance Opening Balance	***Jan. 1/2009***		3,381		
RRRP Approved by OEB					
Annual Rural and Remote Rate Protection		(27,549)		(27,549)	
RRRP Variance Account Recovery		(3,381)		(3,381)	
Total RRRP Received		(30,930)	(30,930)	(30,930)	
Revenues					
Energy		(13,652)		(14,303)	(651)
Other - Late Payment, Service Fees, External		(633)		(609)	24
Total	**Note 1**	(14,285)	(14,285)	(14,912)	(627)
Costs					
OM&A					
Generation		7,795		9,248	(1,453)
Fuel		18,359		21,649	(3,290)
Distribution		1,378		1,648	(270)
Customer Care		1,143		1,230	(87)
Community Relations		394		599	(205)
Administration and Other OM&A		1,266		981	285
External Costs		156		90	66
Bad Debt	**Note 2**	(365)		575	(940)
Depreciation (includes removals)		3,034		2,969	65
Amortization of Environmental Asset		983		1,500	(517)
Other Post Employment Benefits		0		0	0
Interest		1,120		1,720	(600)
Income Tax (Includes capital taxes)		2,944		152	2,792
Total		38,207	38,207	42,361	(4,154)
Net (Income)/Loss [change in RRRP]		(7,008)			
Ending Balance RRRP VA	***December 31/2009***		(3,627)		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2009 were $30,930 thousand. Of that $23,922 thousand was recognized as a revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $365 thousand reflects the impact of lower energy receivables due to successful long term payment arrangements and vigorous residential collections

HYDRO ONE REMOTE COMMUNITIES INC.
Variance Account Reconciliation
For the year ended Dec. 31, 2010

		Revenues and Expenses Audited Actuals		Approved	Variance
RRRP Variance Opening Balance	***Jan. 1/2010***		(3,627)		
RRRP Approved by OEB					
Annual Rural and Remote Rate Protection		(27,549)		(27,549)	
RRRP Variance Account Recovery		0		0	
Total RRRP Received		(27,549)	(27,549)	(27,549)	
Revenues					
Energy		(13,776)		(14,303)	(527)
Other - Late Payment, Service Fees, External		(1,015)		(609)	406
Total	**Note 1**	(14,790)	(14,790)	(14,912)	(121)
Costs			(42,339)		
OM&A					
Generation		10,321		9,248	1,073
Fuel		20,757		21,649	(892)
Distribution		1,824		1,648	176
Customer Care		1,480		1,230	250
Community Relations		309		599	(290)
Administration and Other OM&A		1,087		981	106
External Costs		172		90	82
Bad Debt	**Note 2**	(624)		575	(1,199)
Depreciation		2,975		2,969	6
Amortization of Environmental Asset		1,268		1,500	(232)
Other Post Employment Benefits		0		0	0
Interest		1,113		1,720	(607)
Income Tax (Includes capital taxes)		1,353		152	1,201
Total		42,034	42,034	42,361	(327)
Net (Income)/Loss [change in RRRP]		(305)			
Ending Balance RRRP VA	***December 31/2010***		(3,932)		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2010 were $27,549 thousand. Of that $27,243 thousand was recognized as a revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $624 thousand reflects the impact of lower energy receivables due to successful long term payment arrangements and vigorous residential collections

HYDRO ONE REMOTE COMMUNITIES INC.
Variance Account Reconciliation
For the year ended Dec. 31, 2011

		Revenues and Expenses Audited Actuals		Approved	Variance
RRRP Variance Opening Balance	***Jan. 1/2011***		(3,932)		
RRRP Approved by OEB					
Annual Rural and Remote Rate Protection		(27,549)		(27,549)	
RRRP Variance Account Recovery		0		0	
Total RRRP Received		(27,549)	(27,549)	(27,549)	
Revenues					
Energy		(14,337)		(14,303)	34
Other - Late Payment, Service Fees, External		(752)		(609)	143
Total	**Note 1**	(15,089)	(15,089)	(14,912)	177
Costs			(42,638)		
OM&A					
Generation		10,996		9,248	1,748
Fuel		22,162		21,649	513
Distribution		1,344		1,648	(304)
Customer Care		1,930		1,230	700
Community Relations		444		599	(155)
Administration and Other OM&A		994		981	13
External Costs		129		90	39
Bad Debt	**Note 2**	(196)		575	(771)
Depreciation		3,676		2,969	707
Amortization of Environmental Asset		1,017		1,500	(483)
Other Post Employment Benefits		0		0	0
Interest		1,134		1,720	(586)
Income Tax (Includes capital taxes)		(158)		152	(310)
Total		43,472	43,472	42,361	1,111
Net (Income)/Loss [change in RRRP]		835			
Ending Balance RRRP VA	***December 31/2011***		(3,098)		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2011 were $27,549 thousand. An additonal $835 thousand was recognized as a revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $196 thousand reflects the impact of lower energy receivables due to successful long term payment arrangements and vigorous residential collections

HYDRO ONE REMOTE COMMUNITIES INC.
Variance Account Reconciliation
For the year ended Dec. 31, 2012

		Revenues and Expenses Audited Actuals		Approved	Variance
RRRP Variance Opening Balance	***Jan. 1/2012***		(3,098)		
RRRP Approved by OEB					
Annual Rural and Remote Rate Protection		(27,549)		(27,549)	
RRRP Variance Account Recovery		0		(3,381)	
Total RRRP Received		(27,549)	(27,549)	(30,930)	
Revenues					
Energy		(14,768)		(14,303)	465
Other - Late Payment, Service Fees, External		(489)		(609)	(120)
Total	**Note 1**	(15,257)	(15,257)	(14,912)	345
Costs			(42,806)		
OM&A					
Generation		11,591		9,248	(2,343)
Fuel		22,864		21,649	(1,215)
Distribution		1,902		1,648	(254)
Customer Care		1,689		1,230	(459)
Community Relations		846		599	(247)
Administration and Other OM&A		1,042		981	(61)
External Costs		61		90	29
Bad Debt	**Note 2**	38		575	537
Depreciation		3,491		2,969	(522)
Amortization of Environmental Asset		3,474		1,500	(1,974)
Other Post Employment Benefits		0		0	0
Interest		1,095		1,720	625
Income Tax (Includes capital taxes)		(1,372)		152	1,524
Total		46,721	46,721	42,361	(4,360)
Net (Income)/Loss [change in RRRP]		3,915			
IFRS Transition Account (Removed from RRRP Variance Account)			(70)		
Ending Balance RRRP VA	***December 31/2012***		747		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2012 were $27,549 thousand. The requirement projected is $3,915 higher consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

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*. Under this Act, O. Reg. 442/01 requires the Board to calculate the amount of Rate Protection for these customers. In view of this legislative requirement that sets out rules for setting rates, Remotes did not undertake a cost allocation study as required by Board in the minimum filing requirements (EB-2006-0170) prior to filing this application. A cost allocation study would not have provided any benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation.

Consistent with Remotes' proposal in EB-2008-0232, which was accepted by the Board, 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 2013, Remotes followed the approach approved in the Board's Decision with Reasons for EB-2008-0232. That Decision prescribed the methodology for calculating average rate increases for other Local Distribution Companies ("LDC") to apply in a cost-of-service proceeding. Because Remotes' rates include both generation and distribution services, Remotes has applied the OEB-prescribed methodology to the total bill in order to capture changes to both generation and distribution costs.

Based on this methodology, Remotes calculated the average increase assuming the following: considered both Residential and General Service <50 kW customers; weighted each LDC as "1"; excluded rate riders and adders; assumed monthly consumption of 800 kWh for Residential and 2000 kWh for General Service <50 kW customers. Remotes calculated the average rate increase based on the rate changes approved by the Board in 2011, as the information for 2012 increases is not yet available. The average total bill increase from 2010 to 2011 was 3.45%.

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 2013	Increase
Service Charge	$17.50	$18.10	3.45%
Block 1 *First 1,000 kWh*	$0.0824	$0.0852	3.45%
Block 2 *Next 1,500 kWh*	$0.1098	$0.1136	3.45%
Block 3 *All additional (Over 2,500 kWh)*	$0.1655	$0.1712	3.45%

Residential Seasonal (R4)			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$29.56	$30.58	3.45%
Block 1 *First 1,000 kWh*	$0.0824	$0.0852	3.45%
Block 2 *Next 1,500 kWh*	$0.1098	$0.1136	3.45%
Block 3 *All additional (over 2,500 kWh)*	$0.1655	$0.1712	3.45%

General Service Single Phase (G1)			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$29.72	$30.75	3.45%
Block 1 *First 6,000 kWh*	$0.0922	$0.0954	3.45%
Block 2 *First 7,000 kWh*	$0.1224	$0.1266	3.45%
Block 3 *All additional (over 13,000 kWh)*	$0.1655	$0.1712	3.45%

General Service Three Phase (G3)			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$37.22	$38.50	3.45%
Block 1 *First 25,000 kWh*	$0.0922	$0.0954	3.45%
Block 2 *Next 15,000 kWh*	$0.1224	$0.1266	3.45%
Block 3 *All Additional (Over 40,000 kWh)*	$0.1655	$0.1712	3.45%

Street Lighting			
	Existing Rates	**Proposed 2009**	**Increase**
kWh	$0.0914	$0.0946	3.45%

Standard A Residential Road Rail			
	Existing Rates	**Proposed 2009**	**Increase**
Service Charge	$0.00	$0.00	0%
Block 1 *First 250 kWh*	$0.5418	$0.5605	3.45%
Block 2	$0.6190	$0.6404	3.45%

Standard A Residential Air Access			
	Existing Rates	**Proposed Rates**	**Increase**
Service Charge	$0.00	$0.00	0%
Block 1 *First 250 kWh*	$0.8178	$0.8460	3.45%
Block 2	$0.8951	$0.9260	3.45%

Standard A General Service Road Rail			
	Existing Rates	**Proposed Rates**	**Increase**
Service Charge	0.00	0.00	0%
kWh	$0.6190	$0.6404	3.45%

Standard A General Service Air Access			
	Existing Rates	**Proposed Rates**	**Increase**
Service Charge	0.00	0.00	0%
kWh	$0.8951	$0.9260	3.45%

PROPOSED GRID-CONNECTED CUSTOMER RATES

1.0 INTRODUCTION

In 2010, the Ontario Government amended the *Electricity Act, 1998* (the "Electricity Act") to require Remotes to serve grid-connected communities in accordance with government regulation. The decision to permit Remotes to serve these customers was made to give remote communities connecting to the grid an option of being served by an established electricity distribution company and in anticipation that these customers will qualify for rate protection if served by Remotes.

Remotes believes that service to geographically remote communities will be more expensive than service to communities that are more accessible. Moreover, the provision of electricity in First Nation communities across the remote north has historically been supported by the federal government. Remotes and most of the Independent First Nation Power Authorities have historically set rates for government customers above cost to help cover the operating costs and to keep rates for residential customers affordable. As a result, rates for residential and small commercial customers are quite low when compared to rates for grid-connected customers.

To ensure that residential customers whose communities connect to the grid do not experience significant rate increases, Remotes plans to include non-Standard A grid-connected residential and general service customers in its existing non-Standard A Residential and General Service rate classes. Offering grid-connected non-Standard A customers the same rates as other residential and general service customers in Remotes' service territory will reduce potential rate impacts if communities that Remotes currently serves connect to the grid.

Under the RRRP regulation, Standard A (government funded) customers do not benefit from Rate Protection. Remotes anticipates that grid-connected Standard A customers will not be eligible for rate protection. Moreover, Remotes' Standard A rates, like those in most communities in the far north, are set slightly above the average cost of service.

To develop the grid-connected Standard A rate, Remotes first estimated the current "implicit" generation cost embedded in its Standard A rates. The implicit generation costs consist of the generation related costs as well as a proportionate share of Shared Services and Other Costs (Exhibit C1, Tab 2, Schedule 6). The implicit generation costs in Remotes' 2012 Standard A rate are shown below:

Table 1

2012 Generation Costs Excluding Fuel

2012 Generation Costs	**($000's)**
Operations & Maintenance (excluding fuel)	9,577
Environmental OM&A[1]	339
Generation Depreciation	2,371
Land Assessment and Remediation (Amortization)	3,473
Administrative	517
Total Generation Costs Excluding Fuel	**16,277**

To determine the per kWh generation cost, Remotes divided the total generation costs excluding fuel by the projected kWh sold.

[1] Environmental costs are comprised only of generation-related costs and include 50% of the legislative monitoring costs and environmental costs related to fuel spills.

Table 2

Per kWh Off-Grid Generation Costs

Total Generation Costs Excluding Fuel ($000)	16,277
kWh sold (000's projected)	55,806
Cost per kWh off-grid generation ($/kWh)	**0.2917**

Fuel costs vary from year to year depending on external factors such as market prices and the availability of winter roads. To determine an appropriate proxy for fuel costs, Remotes took the three-year average cost per kWh for air access communities.

Table 3

Air Access kWh Fuel Costs

	2009	2010	2011
MWh Sold	47,293	46,094	48,129
Annual Air Access Fuel Costs ($000's)	$17,057	$19,405	$20,374
Three Year Average MWh Sold	47,172		
Three Year Average Fuel Costs ($000's)	$18,945		
Three Year Average $/kWh	**0.4016**		

In order to estimate the cost of power if delivered through the transmission grid, Remotes considered the charges that would typically be paid by a grid-connected customer. The commodity charge is estimated to be the 2011 weighted average cost of power per the IESO December, 2011 Monthly Market Report. The estimated Wholesale Market Service Charge and RRRP charges are those currently in effect. The cost of Transmission service is estimated based on Retail Transmission Service Rates (RTSR) for General Service Energy customers requested for approval in Hydro One Networks Inc.'s 2013 rate application (EB-2012-0031). Line losses are estimated at Remotes' current line losses.

Table 4

Estimated Cost of Grid-delivered Power

Commodity	0.07200
Wholesale Market Service Charge	0.00520
RRRP	0.00110
RTSR - Network	0.00518
RTSR - Line	0.00358
Cost of Grid-delivered Power	0.0871
Line Losses @ 1.5%	0.0013
Total Cost of Grid-delivered Power	**0.0884**

In order to calculate the proposed Standard A Grid Connected Rate, Remotes took the 2012 Standard A General Service Air Access Rate and subtracted the generation and fuel costs and added the cost of Grid-delivered power.

Table 5

Proposed Grid Connected Standard A Rates

Standard A General Service Air Access Rates (Exhibit G1-1-1)	0.8951
Remotes' Generation Costs Excluding Fuel (Table 2)	(0.2917)
Air Access Fuel 3 Year Average (Table 3)	(0.4016)
Cost of Grid Power (Table 4)	0.0884
Grid-connected Standard A Rate	**0.2902**

RURAL AND REMOTE RATE PROTECTION REQUIREMENT

1.0 INTRODUCTION

Remotes has two broad categories of customers, Standard A or government customers whose rates have historically been 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. Distributors and the IESO bill all electricity users for the $0.0011/kWh charge on all electricity consumed, generating approximately $156 million per year of RRRP revenues. Under current Board-approved processes, Hydro One Networks Inc. 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 Inc. distributes Remotes' OEB-approved share of RRRP revenues in equal installments throughout the year.

Remotes operates under a cost-recovery model applied to achieve an after-tax break-even operating result. Any excess or deficiency in RRRP revenues necessary to break-even is added to, or drawn from, the RRRP Variance Account. Further information about this account can be found in Exhibit F, Tab 1, Schedule 1.

RRRP transfers account for over half of Remotes' revenues each year. RRRP for customers in Remotes' service area is currently set at $27,549 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 FOR OFF-GRID COMMUNITIES

Remotes tracks detailed monthly data on customer numbers and kWh usage by community and by class. This historical data provides the baseline for forecasting revenue usage / kWh sold. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes.

Historical trends include the impact of Remotes' Conservation and Demand Management (CDM) program, but forecast program results are not specifically included in the forecast. CDM program results have varied considerably since the program's inception based on the availability of energy advisors in the communities. One of Remotes' lessons learned in conservation is that if conservation measures are to be effective and persistent, the development of local expertise is critical. Remotes is constantly improving its approach by improving support to energy advisors and by involving Band Councils more directly in the program, but the program itself is still very new and small.

Three additional sources of information are also used in compiling this forecast: Band Councils, AANDC and employees. Each year, Remotes solicits information from Band Councils on planned construction projects. Remotes also holds an annual planning meeting with AANDC for information on program activities that could affect load. Finally, field employees share information about pending connections, in particular when these connections are material, such as the construction of a housing subdivision, school or water treatment plant. Employees are also canvassed for information on communities where generation capacity has reached its limits, forcing a constraint on future near-term load growth.

This analysis of forecast load is not checked against external forecasts as these forecasts are not appropriate to use to forecast load in Remotes' service territory. Most of the communities Remotes` serves are northern First Nation reserves, which are not specifically addressed in external reports such as the CMHC Outlook. Furthermore, key market indicators for most external reports such as housing growth do not necessarily apply within remote First Nation reserves. Similarly, an upturn in the overall Canadian or Ontario economy has not historically resulted in a similar increase in economic activity within these communities. In the case of the link between population growth and increases in housing units, for example, increases in population within the communities do not tie directly to an increase in the number of houses. A February 2011 audit report that evaluated AANDC`s on reserve housing support found, for example, that ``while housing stock has increased steadily since 1996 through construction of new units and repairs to damaged units, the results have not kept pace with housing needs. ``[1] Moreover, that same report found that even the rate of new housing construction on Canadian reserves does not directly correlate to an increased number of housing units because "the housing build on reserve is not lasting as long as it should and needs replacing sooner than can be afforded."

Remotes does not weather correct its load forecast for three reasons: its communities are very small and are scattered within a wide territory; reliable historical weather station data is not available for any communities within Remotes' service territory (the closest reliable data is for Thunder Bay); and because Remotes is operated as a break-even business, it does not stand to

[1] Evaluation of INAC`s On-Reserve Housing Support, February 2011, Chapter 5. Available on AANDC`s website: http://www.aadnc-aandc.gc.ca/aiarch/arp/aev/pubs/ev/orhs/orhs-eng.asp#exe

profit as a result of forecasting errors. Historical usage data does help to smooth out weather related load changes. Revenues are calculated based on the rate class usage characteristics and the applicable rate schedules.

Tables 1 and 2 below show the 2013 load forecast by category and customer class.

Table 1

2013 Non Standard A Load Forecast by Customer Class

Non Standard A						
	Residential	**Seasonal**	**GS 1 Phase**	**GS 3 Phase**	**Streetlight**	**Total**
Effective # of Customers	2,595	164	279	27	6	3,071
Average kWh's/Customer	13,537	2,153	20,212	133,901	37,337	207,138
Total MWh's	**35,126**	**353**	**5,648**	**3,615**	**224**	**44,966**

Table 2

2013 Standard A Load Forecast by Customer Class

Standard A					
	Residential Road Rail	**Residential Air Access**	**GS Road Rail**	**GS Air Access**	**Total**
Effective # of Customers	12	114	27	305	458
Average kWh's/Customer	5,365	11,275	24,022	30,990	
Total MWh's	**65**	**1,289**	**649**	**9,461**	**11,464**

Table 3 shows the Revenue forecast by Standard A and Non Standard A customer categories.

Table 3

2013 Revenue Forecast at Current Rates($000s)

Community	**Non Standard A**		**Standard A**		**Total**	
	MWh	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
Armstrong	3,629	$412	387	$238	4,016	$650
Marten Falls	845	$72	322	$287	1,167	$359
Bearskin Lake	2,012	$217	717	$640	2,729	$857
Big Trout Lake	5,105	$547	871	$777	5,976	$1,324
Biscotasing	469	$68	-	$0	469	$68
Deer Lake	3,704	$398	1,195	$1,067	4,899	$1,465
Fort Severn	1,724	$189	644	$574	2,368	$763
Gull Bay	950	$105	327	$201	1,277	$306
Hillsport	242	$30	-	$0	242	$30
Kasabonika	3,351	$359	861	$767	4,212	$1,126
Kingfisher	1,704	$182	638	$570	2,342	$752
Lansdowne	1,304	$138	532	$475	1,836	$613
Oba	201	$29	-	$0	201	$29
Sachigo Lake	2,176	$296	703	$629	2,879	$925
Sandy Lake	9,097	$988	2,299	$2,053	11,396	$3,041
Sultan	465	$61	-	$0	465	$61
Wapakeka	2,049	$223	548	$489	2,597	$712
Weagamow	3,766	$408	706	$631	4,472	$1,039
Webequie	2,173	$231	714	$637	2,887	$868
Total	**44,966**	**$4,953**	**11,464**	**$10,035**	**56,431**	**$14,988**

Table 4 shows the revenue forecast by customer category at proposed 2013 rates.

Table 4

2013 Revenue Forecast at 2013 Proposed Rates ($000s)

Community	Non Standard A		Standard A		Total	
	MWh	Revenue	MWh	Revenue	MWh	Revenue
Armstrong	3,629	$421	387	$243	4,016	$664
Marten Falls	845	$74	322	$293	1,167	$367
Bearskin Lake	2,012	$222	717	$655	2,729	$877
Big Trout Lake	5,105	$559	871	$795	5,976	$1,354
Biscotasing	469	$70	-	$0	469	$70
Deer Lake	3,704	$407	1,195	$1,092	4,899	$1,499
Fort Severn	1,724	$192	644	$588	2,368	$780
Gull Bay	950	$107	327	$206	1,277	$313
Hillsport	242	$30	-	$0	242	$30
Kasabonika	3,351	$368	861	$785	4,212	$1,153
Kingfisher	1,704	$186	638	$583	2,342	$769
Lansdowne	1,304	$141	532	$486	1,836	$627
Oba	201	$30	-	$0	201	$30
Sachigo Lake	2,176	$303	703	$643	2,879	$946
Sandy Lake	9,097	$1,011	2,299	$2,100	11,396	$3,111
Sultan	465	$62	-	$0	465	$62
Wapakeka	2,049	$228	548	$500	2,597	$728
Weagamow	3,766	$418	706	$645	4,472	$1,063
Webequie	2,173	$236	714	$652	2,887	$888
Total	**44,966**	**$5,065**	**11,464**	**$10,266**	**56,431**	**$15,331**

The revenue from proposed rates is shown with a May 1, 2013 implementation date. The proposed increase has been pro-rated to show this implementation date.

3.0 LOAD AND REVENUE FORECAST FOR GRID-CONNECTED COMMUNITIES

Remotes does not have historical load information for geographically remote grid-connected communities. The number of customers by category for each community as shown in table 5 below has been estimated based on available information about number of customers and population size. For example, the community of Pikangikum provided a rough estimate of customers and load. Because of generation constraints related to the diesel plant in the community, however, community and load growth has been very constrained for many years. It is anticipated that a grid connection will allow the community to grow again, and because Pikangikum has a population similar to Sandy Lake, information from Sandy Lake has been used in this forecast. Detailed information was also not available for Cat Lake. Cat Lake is of a similar size to Marten Falls, so information about load and customers in Marten Falls was used to develop the load forecast. Load and revenue projections for the two communities are shown below in Table 5.

Table 5
Load and Revenue Forecast for Grid-Connected Customers
($000)

Community	**Non Standard A**		**Standard A**		**Total**	
-	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
Pikangikum	8,497	$954	2,186	$656	10,682	$1,610
Cat Lake	1,291	$130	630	$189	1,921	$319
Total	9,788	$1,084	2,816	$845	12,603	$1,929

Table 6

Forecast Revenues from Customers

($000)

Community	Non Standard A MWh	Non Standard A Revenue	Standard A MWh	Standard A Revenue	Total MWh	Total Revenue
Total Grid Connected	9,788	$1,084	2,816	$845	12,603	$1,929
Total Existing Communities	44,966	$5,065	11,464	$10,266	56,431	$15,331
Total	**54,754**	**$6,149**	**14,280**	**$11,111**	**69,034**	**$17,260**

4.0 FORECAST RRRP REQUIREMENT

Table 7

Forecasted RRRP Requirement

($000s)

Item		
2013 Revenue Requirement		**$52,284**
Less:	2013 Revenue from Customer Rates	**($17,260)**
	Other Revenues	**($514)**
Annual RRRP Level for 2013		**$34,510**
Recovery of Balance of RRRP Variance acct and other Regulatory accounts		**$819**
Total RRRP Level for 2013		**$35,329**

CUSTOMER BILL IMPACTS

1.0 INTRODUCTION

The impacts of the proposed changes for Remotes' current customers are shown in Tables 1 to 4 below. The rates have been increased by 3.45%: the total bill impacts may differ slightly from 3.45% because the rates levied to customers are rounded at the appropriate decimal place (four for kWh charges and two for service charges), Bill impacts are not calculated for customers in Cat Lake and Pikangikum because there are no OEB-approved rate orders for these communities. Most of Remotes' customers are First Nation, living on reserve and are exempt from HST and DRC. HST and DRC calculations are therefore not included in this analysis.

2.0 RESIDENTIAL YEAR ROUND (R2)

The Year-Round Residential classification applies to a customer's principal residence 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 2013 rates compared to the current 2012 rates. The analysis is based on the total bill, including a monthly service charge. Because the majority of Remotes' customers are First Nation and are on reserve, Debt Retirement Charges and HST are not included in the calculations. The Ontario Clean Energy Benefit is included.

Table 1

Bill Impacts for Residential (R2) Customers

RESIDENTIAL YEAR ROUND (R2)					
Scenario (kWh)	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
100	$25.74	$23.16	$26.62	$23.96	3.43%
250	$38.10	$34.29	$39.40	$35.46	3.42%
500	$58.70	$52.83	$60.70	$54.63	3.41%
800	$83.42	$75.08	$86.26	$77.63	3.41%
1000	$99.90	$89.91	$103.30	$92.97	3.41%
2000	$209.70	$188.73	$216.90	$195.21	3.43%

3.0 RESIDENTIAL SEASONAL (R4)

This classification is comprised of cottages, chalets and camps or any other residential service not meeting the year-round residential 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.

Table 2

Bill Impacts for Residential Seasonal (R4) Customers

RESIDENTIAL SEASONAL (R4)					
Scenario KWh	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
100	$37.80	$34.02	$39.10	$35.19	3.44%
250	$50.16	45.14	$51.88	46.69	3.44%
500	$70.76	63.68	73.18	65.86	3.45%
800	95.48	85.93	98.74	88.87	3.41%
1000	111.96	100.76	115.78	104.20	3.41%
2000	221.76	199.58	229.38	206.44	3.44%

4.0 GENERAL SERVICE SINGLE PHASE

This classification applies to any non-Standard A service that does not fit the description of the year-round residential or seasonal residential. 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.

Table 3

Bill Impacts for General Service Single Phase (G1)

GENERAL SERVICE SINGLE PHASE (G1)					
Scenario KWh	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
1000	$121.92	$109.73	$126.15	$113.54	3.47%
2000	$214.12	$192.71	$221.55	$199.40	3.47%
3000	$306.32	$275.69	$316.95	$285.26	3.47%
5000[1]	$490.72	$460.09	$507.75	$476.06	3.47%

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.

Table 4

Bill Impacts for General Service (G3)

GENERAL SERVICE THREE PHASE (G3)					
Scenario KWh	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
1000	$129.42	$116.48	$133.90	$120.51	3.46%
2000	$221.62	$199.46	$229.30	$206.37	3.47%
3000	$313.82	282.44	324.70	292.23	3.47%
5000[2]	$498.22	$466.84	$515.50	$483.03	3.45%

[1] As of September, 2012, the 10% OCEB applies only to the first 3,000 kWh per month. Bill credits of $30.63 for current rates and $31.70 for proposed rates have been applied to the 5000 kWh usage.
[2] As of September, 2012, the 10% OCEB applies only to the first 3,000 kWh per month. Bill credits of $31.38 for current rates and $32.47 for proposed rates have been applied to the 5000 kWh usage.

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.

Table 5

Bill Impacts for Standard A Residential Road/Rail

STANDARD A RESIDENTIAL ROAD/RAIL					
Scenario (kWh)	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
100	$54.18	$48.76	$56.05	$50.45	3.45%
250	$135.45	$121.91	$140.13	$126.11	3.45%
500	$290.20	$261.18	$300.23	$270.20	3.45%
800	$475.90	$428.31	$492.35	$443.11	3.46%
1000	$599.70	$539.73	$620.43	$558.38	3.46%
2000	$1,218.70	$1,096.83	$1,260.83	$1,134.74	3.46%

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.

Table 6

Bill Impacts for Standard A Residential Air Access

STANDARD A RESIDENTIAL AIR ACCESS					
Scenario (kWh)	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
100	$81.78	$73.60	$84.60	$76.14	3.45%
250	$204.45	$ 184.01	$211.50	$190.35	3.45%
500	$428.23	$385.40	$443.00	$398.70	3.45%
800	$696.76	$627.08	$720.80	$648.72	3.45%
1000	$875.78	$788.20	$906.00	$815.40	3.45%
2000	$1,770.88	$1,593.79	$1,832.00	$1,648.80	3.45%

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.

Table 7

Rate Impacts for Standard A General Service Road/Rail

STANDARD A GENERAL SERVICE ROAD RAIL					
Scenario (kWh)	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
1000	$619.00	$557.10	$640.40	$576.36	3.46%
2000	$1,238.00	$1,114.20	$1,280.80	$1,152.72	3.46%
3000	$1,857.00	$1,671.30	$1,921.20	$1,729.08	3.46%
5000[3]	$2,476.00	$2,228.40	$2,561.60	$2,305.44	3.46%

[3] As of September, 2012, OCEB is applied only to the first 3,000 kWh of usage. A credit of $185.70 has been applied to current rates and $192.12 to proposed rates for the 5,000 kWh usage.

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.

Table 8

Rate Impacts for Standard A General Service Air Access

STANDARD A GENERAL SERVICE AIR ACCESS					
Scenario (kWh)	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
1000	$ 895.10	$805.59	$926.00	$833.40	3.45%
2000	$1,790.20	$1,611.18	$1,852.00	$1,666.80	3.45%
3000	$2,685.30	$2,416.77	$2,778.00	$2,500.20	3.45%
5000[4]	$4,475.50	$4,206.97	$4,630.00	$4,352.20	3.45%

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.

[4] As of September 12, 2012, the OCEB applies only to the first 3000 kWh. A credit of $268.53 has been applied to current rates and $277.80 to proposed rates for the 5000 kWh usage.

Table 9

Rate Impacts for Streetlights

STREET LIGHTING					
Scenario KWh	**Current Bill**	**Current Bill with OCEB**	**Propose d Bill**	**Proposed Bill with OCEB**	**Percentage Change**
100	$9.14	$8.23	$9.45	$8.51	3.50%
200	$18.28	$16.45	$18.92	$17.03	3.50%
300	$27.41	$24.68	$28.38	$25.54	3.50%
400	$36.55	$32.90	$37.84	$34.06	3.50%
500	$45.69	$41.13	$47.30	$42.57	3.50%

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

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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.
21. Marten Falls.

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	
Family Day	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, 2012, 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 bus 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 bus 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' 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 seven (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 Disconnection/Load Control Process for Reasons of Non-payment

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 at least 21 days 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.

If a bill remains unpaid in whole or in part when a bill for the next month is issued, and if the second bill remains unpaid in whole or in part, then nineteen (19) calendar days after the billing date of the second bill and at least:

i. sixty (60) calendar days after a written Disconnection notice has been provided to the Customer by personal service, prepaid mail or by posting notice on the property in a conspicuous place, if the Customer is a residential Customer who has provided Remotes with documentation from a physician confirming that Disconnection poses a risk of significant adverse effects on the physical health of the Customer or on the physical health of the Customer's spouse, dependent family member or other person that regularly resides with the Customer or
ii. in all other cases, fifteen (15) calendar days after a written Disconnection notice has been provided to the customer by mail, personal service or by posting notice on the property in a conspicuous place.

Remotes may fully interrupt or control the distribution of electricity to the Customer.

In accordance with Section 4.2.1 of the Distribution System Code, Remotes shall provide the Customer being Disconnected for non-payment the Fire Safety Notice of the Office of the Fire Marshall and any other public safety notices or information bulletins issued by public safety authorities and provided to Remotes, which provide information about dangers associated with the Disconnection of electricity service.

A residential Customer may designate a third party to also receive a copy of the notices set out in this Section provided that the request is made no later than the last day of the applicable minimum notice period set out in this Section.

Remotes shall suspend any Disconnection action for twenty-one (21) days from the date of notification by registered charity, government agency or social service agency that is assessing a residential Customer for the purposes of determining whether the Customer is eligible to receive bill payment assistance, provided such notification is made within 21 days from the date on which the Disconnection notice is received by the Customer. Where the Customer has designated a third party to receive a copy of any Disconnection notice, and such third party notifies Remotes that he or she is attempting to arrange assistance with the bill payment, Remotes shall suspend all Disconnection action for 21 days provided such notification is made within 21 days from the date on which the Disconnection notice is received by the Customer. Upon notification by a registered charity, government agency or social service agency that the residential Customer is not eligible to receive bill payment assistance, or if the third party decides not to assist the Customer with the bill payment, Remotes may proceed with the Disconnection process.

2.2.2 Immediate Disconnection without Notice

Remotes reserves the right to Disconnect the Distribution of electricity to a Customer, without notice, in accordance with a court order, a request by a fire department or for emergency, public safety (including potential for loss of life or limb), system reliability reasons or in order to inspect, maintain, repair, alter, remove, replace or Disconnect wires or other facilities used to distribute electricity or where there is an energy diversion, fraud or abuse on the part of the customer.

2.2.3 Liability for Disconnection

Disconnection does not relieve the Customer of the liability for arrears or minimum bills for the balance of the term of the contract. The Customer shall be liable for any third party costs incurred by Remotes which are necessary to effect a Disconnection.

Under no circumstances will Remotes be liable for any damage resulting from, associated with or related to the Disconnection or the control of distribution of electricity, including damage to the Customer or the Customer's premises and any business or other losses suffered by Customer as a result of the Disconnection.

2.2.4 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; or
(e) where it is a requirement of the Electrical Safety Code.

2.2.5 Disconnection and Reconnection Related Charges

a) Disconnection for Non Payment

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.

b) Unauthorized Energy Use

If Remotes has Disconnected a Customer for causes including energy diversion, fraud or abuse on the part of the customer, such service shall not be Reconnected until the Customer rectifies the condition and pays all uncollected charges, including late payment charges as determined by Remotes and costs incurred by Remotes arising from unauthorized energy use, including inspections and repair costs, and the cost of Disconnection and Reconnection.

c) Service Cancellation

Where a Customer requests a service cancellation, Remotes will remove certain delivery equipment, such as power lines, transformers and meter. If Reconnection is requested, the Customer will incur a cost to reinstall appropriate delivery equipment and shall follow the steps and processes for new connections set out in these Conditions of Service.

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 will endeavor to provide as much notice as possible, but at least twenty-four (24) hours' notice. Notice is provided through the media, the Band Office (where applicable) and through posters. Remotes may, but is not obligated to, notify affected Customers in advance of planned power interruptions and has the right to interrupt without notice. In emergencies, Remotes will not provide prior notification of an interruption.

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 than 5% of the smallest diesel generator’s capacity. Any motors that are larger than 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 System Voltages	Recommended Voltage Variation Limits for Circuits up to 1000 volts, at the Service Entrance.			
	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 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 two-year period from the date that Remotes is notified of the problem.

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 on 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 on 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.

In the event that Remotes applies all or part of a security deposit to offset amounts owing by a residential Customer, Hydro One may require the Customer to repay the amount of the security deposit that was so applied.

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. Billing Cycle Factors shall be 2.5 for monthly-billed customers, 1.75 for bi-monthly billed Customers and 1.5 for quarterly-billed customers.

Account security deposit levels for new Customers or Customers who have no payment history with Remotes shall be determined based on average monthly 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.

Remotes will review security deposits at least once each calendar year to determine whether the entire amount is to be returned to the Customers. Refund of account security on residential accounts occurs when a satisfactory payment record is demonstrated over 12 consecutive months. For all other accounts, the account security deposit will be held until a satisfactory payment record is demonstrated over 5 years. When a residential or other Customer account is terminated, the security amount will be credited on the Customer's final bill and any surplus will be refunded by cheque.

Interest on cash security deposits shall accrue monthly commencing on the receipt of the total deposit required. The interest rate shall be at the prime business rate, as indicated on the Bank of Canada Web site, less two (2) per cent, updated quarterly, to a minimum of zero per cent. The interest will be credited on the Customer's bill on a quarterly basis.

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. 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/pre-authorized payments.

2.4.5.2 Late Payment Charges

Bills are due on the billing date. A late payment charge is applied and shall be paid by the Customer if payment is not received within nineteen (19) days of the billing date. Remotes provides customers with a 16-day payment period, plus 3 days for the bill to be sent. The required payment date printed on the bill is set 19 days after the billing date. When a required payment date is a weekend or holiday, the payment will be required on the next business day.

Remotes' late payment charge is set at 1.5 per cent compounded monthly (19.56 per cent per annum). Late payments are calculated from the billing date to the date the next bill is issued. Where a partial payment has been made within nineteen (19) days of the billing date, the late payment charge will apply only to the amount of the bill outstanding after deducting the partial payments.

An allowance of three (3) days is provided after the required payment date, to allow for payment receipt by mail.

Customers who are on electronic funds transfer/pre-authorized payment will have their payment amount automatically withdrawn from their designated bank account on the 19th day after the billing date. The withdrawal date and amount is clearly indicated on each bill.

2.4.5.3 Allocation of Payments

Any payments received will be applied to the total outstanding balance of the electricity account. An outstanding balance could include the billed amounts, security deposits, late payment or other charges. Payment cannot be directed to specific portions of the outstanding balance.

2.5 Customer Information

Remotes shall not disclose specific information about a Customer unless the release of information has been authorized 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'

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 a 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.

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:

- Canada Post Corporation, the Services Corporation or a subsidiary of the Services Corporation;
- Social housing;
- A library;
- A recreational or sports facility;
- Radio, television or cable television facility.

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 Aboriginal Affairs and Northern Development 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 on 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" means 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;

"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, 2013

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, 2013 for all consumption or deemed consumption service used on or after that date

MISCELLANEOUS CHARGES – May 1, 2013 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, 2013

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

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, 2013

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

microFIT Generator Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to a Hydro One Remote Community distribution system.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2013

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

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.

Standard A Grid-Connected

This classification is applicable to all Standard A customers in communities that are connected to the grid and are not accessible by a year-round road or by rail.

MONTHLY RATES AND CHARGES

Year-Round Residential – R2

Service Charge	$	18.10
Energy Charge First 1,000 kWh	$/kWh	0.0852
Energy Charge Next 1,500 kWh	$/kWh	0.1136
Energy Charge All Additional kWh	$/kWh	0.1712

Seasonal Residential – R4

Service Charge	$	30.58
Energy Charge First 1,000 kWh	$/kWh	0.0852
Energy Charge Next 1,500 kWh	$/kWh	0.1136
Energy Charge All Additional kWh	$/kWh	0.1712

General Service Single Phase – G1

Service Charge	$	30.75
Energy Charge First 6,000 kWh	$/kWh	0.0954
Energy Charge Next 7,000 kWh	$/kWh	0.1266
Energy Charge All Additional kWh	$/kWh	0.1712

General Service Three Phase – G3

Service Charge	$	38.50
Energy Charge First 25,000 kWh	$/kWh	0.0954
Energy Charge Next 15,000 kWh	$/kWh	0.1266
Energy Charge All Additional kWh	$/kWh	0.1712

Street Lighting

Energy Charge	$/kWh	0.0946

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2013

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Standard A Residential Road/Rail

Energy Charge First 250 kWh	$/kWh	0.5605
Energy Charge All additional kWh	$/kWh	0.6404

Standard A Residential Air Access

Energy Charge First 250 kWh	$/kWh	0.8460
Energy Charge All additional kWh	$/kWh	0.9260

Standard A General Service Road/Rail

Energy Charge	$/kWh	0.6404

Standard A General Service Air Access

Energy Charge	$/kWh	0.9260

Standard A Grid-connected

Energy Charge	$/kWh	0.2902

mircoFIT Generator Service Classification	$	5.25

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2013

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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

REMOTES RATE SCHEDULE – CURRENT
Hydro One Remote Communities Inc.
TARIFF OF RATES AND CHARGES

Effective May 1, 2012
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, 2012 for all consumption or deemed consumption service used on or after that date

MISCELLANEOUS CHARGES – May 1, 2012 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, 2012

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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, 2012

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microFIT Generator Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to a Hydro One Remote Community distribution system.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2012

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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	$	17.50
Energy Charge First 1,000 kWh	$/kWh	0.0824
Energy Charge Next 1,500 kWh	$/kWh	0.1098
Energy Charge All Additional kWh	$/kWh	0.1655

Seasonal Residential – R4

Service Charge	$	29.56
Energy Charge First 1,000 kWh	$/kWh	0.0824
Energy Charge Next 1,500 kWh	$/kWh	0.1098
Energy Charge All Additional kWh	$/kWh	0.1655

General Service Single Phase – G1

Service Charge	$	29.72
Energy Charge First 6,000 kWh	$/kWh	0.0922
Energy Charge Next 7,000 kWh	$/kWh	0.1224
Energy Charge All Additional kWh	$/kWh	0.1655

General Service Three Phase – G3

Service Charge	$	37.22
Energy Charge First 25,000 kWh	$/kWh	0.0922
Energy Charge Next 15,000 kWh	$/kWh	0.1224
Energy Charge All Additional kWh	$/kWh	0.1655

Street Lighting

Energy Charge	$/kWh	0.0914

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2012

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Standard A Residential Road/Rail

Energy Charge First 250 kWh	$/kWh	0.5418
Energy Charge All additional kWh	$/kWh	0.6190

Standard A Residential Air Access

Energy Charge First 250 kWh	$/kWh	0.8178
Energy Charge All additional kWh	$/kWh	0.8951

Standard A General Service Road/Rail

Energy Charge	$/kWh	0.6190

Standard A General Service Air Access

Energy Charge	$/kWh	0.8951

mircoFIT Generator Service Classification	$	5.25

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2012

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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